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Impacts of Variable Renewable Energy on Wholesale Markets and Generating Assets in the United States: A Review of Expectations and Evidence

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ABSTRACT

We synthesize available literature, data, and analysis on the degree to which growth in variable renewable energy (VRE) has impacted or might in the future impact bulk power system assets, pricing, and costs in the United States. Most studies of future scenarios indicate that VRE reduces wholesale energy prices and capacity factors of thermal generators. Traditional baseload generators are more exposed to these changing market conditions than low-capital cost and more flexible intermediate and peak-load generators. From analysis of historical data we find that VRE is already influencing the bulk power market through changes in <u>temporal and geographic</u> patterns areas with higher levels of VRE. The most significant observed impacts have concentrated in areas with significant VRE and/or nuclear generation along with limited transmission, with negative pricing also often occurring during periods with lower system-wide load. So far, however, VRE, has had a relatively modest impact on historical <u>average</u> annual wholesale prices across entire market regions, at least in comparison to other drivers. The reduction of natural gas prices is the primary contributor to the decline in wholesale prices since 2008. Similarly, VRE impacts on thermal plant retirements have been limited and there is little relationship between the location of recent retirements and VRE penetration levels. Although impacts on wholesale prices have been modest so far, impacts of VRE on the electricity market will be more significant under higher VRE penetrations.

KEYWORDS
Variable renewable energy; electricity markets; electricity prices; generator profitability

ABBREVIATIONS

AS	Ancillary services
CAISO	California Independent System Operator
CCGT	Combined cycle gas turbine
CREZ	Competitive Renewable Energy Zones
CT	Combustion turbine
DOE	Department of Energy
EGEAS	Electric Generation Expansion Analysis System
EIA	Energy Information Administration
EI	Eastern interconnection
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EWITS	Eastern Wind Integration and Transmission Study
ISO	Independent system operator
ISO-NE	ISO New England
LBNL	Lawrence Berkeley National Laboratory
LMP	Locational marginal price
MISO	Midcontinent Independent System Operator
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
PTC	Production tax credit
PV	Photovoltaics
REC	Renewable energy credit
RPS	Renewables portfolio standard
RT	Real-time
RTO	Regional transmission organization
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
VRE	Variable renewable energy
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study

1. Introduction

Wholesale power prices and the composition and operation of the bulk power system in the United States have witnessed changes in recent years, and concern has grown in some quarters about the effects of variable renewable energy (VRE) on these trends. The U.S. Department of Energy's (DOE) recent "Staff Report to the Secretary on Electricity Markets and Reliability" addressed this concern, but within a much broader context [1]. The study focused on thermal-plant retirements and reliability, and placed a spotlight not only on growth in VRE but also on the effects of other contemporaneous trends such as declining natural gas prices, limited load growth, and regulatory pressures.

As input into the DOE Staff Report, Lawrence Berkeley National Laboratory and Argonne National Laboratory prepared a study [2] that focused on the degree to which growth in VRE has impacted wholesale power prices and bulk power system assets to date and how this may change in the future. Here we present our synthesis of available literature, data and analysis on the degree to which growth in VRE has influenced or might in the future impact wholesale markets and generating assets in the U.S. Specifically, we highlight the possible impacts of VRE on wholesale power market pricing, operation of other power plants, and incentives for generation asset retirement and investment. Where possible, we frame these past or prospective impacts of VRE within the context of other possible drivers for some of the same trends. In Section 3, our synthesis examines results from U.S. studies that rely on detailed power system models, then in Section 4 we focus on observations of historical market data to show the impact of VRE to date.

We highlight up front several important notes on the scope and limitations of this work. First, this paper is primarily a synthesis of the available literature and data. While the literature is broad and deep it is far from complete. Analyzing the impacts of VRE on bulk power markets is a complex area of research and there is much more work to be pursued in this area. Second, this paper is largely focused on restructured, wholesale electricity markets. While many of the issues addressed are also relevant to regions with vertically-integrated electric utilities this is not always the case. Third, this paper does not comprehensively address issues related to short-time-scale variations in VRE and technical characteristics of VRE as they affect power system reliability and VRE integration. Fourth, this paper does not address market design and compensation mechanism design given the changing mix of generation resources, which is a focus of much recent research and debate [1,3–10]. Finally, while we seek to draw some generalizable conclusions from the available market data and literature, all of the issues addressed are highly context dependent — affected by the underlying generation mix of the system, the amount of wind and solar penetration, and the design and structure of the bulk power system in each region. Therefore, we do not analyze impacts to specific power plants, instead focusing on identifying national and regional system-level trends. Regional differences are extensive in the electricity sector, and thus conclusions may differ from one region to the next.

2. Unique Attributes of VRE that Can Impact the Bulk Power Market

All generation types are unique in some respect, imposing varying forms of physical and operational limitations, and wholesale markets and industry investments and operations have evolved over time to manage new challenges. Wind and solar photovoltaics (PV), meanwhile, have four somewhat-unique characteristics that can influence wholesale market prices and generation assets [11–13].

- Weather-driven variability in electricity production, which can impact energy and capacity markets as well as ramping and ancillary service needs
- Uncertainty in forecasts of future output, which can impact ancillary service needs and costs
- Resource-driven location dependencies that, in some cases, can impact the need for or benefit of new transmission investment
- Low, or even negative marginal costs, which tend to place VRE before resources in the dispatch merit order

To further clarify the last point, it is important to understand that wind energy in the U.S. receives a 10-year federal production tax credit (PTC), an incentive that is currently being phased-out over a multi-year period (at times, wind plants have also had the opportunity to take investment-based support in lieu of the PTC). Additionally, both solar and wind benefit from renewables portfolio standards (RPS) in many states. Both the PTC and the RPS create incentives for VRE plant owners and purchasers to bid that generation into wholesale markets at negative prices. The reason is simple: curtailment of generation will result in not only lost energy-based revenue but also potentially lost incentive value [4]. Nor are these policy incentives the only reason that a VRE project may bid at negative price: market demand for 'green energy' by residential, corporate, and governmental entities yields positive prices for renewable energy certificates (RECs), even in the absence of RPS programs.

Given those characteristics of VRE, increasing the share of VRE tends to reduce average wholesale energy prices (LMPs), at least in the short term. All else being equal, lower wholesale electricity prices will generally result in reduced revenues for generation units. These reduced revenues may place particular strain on the operating profits of inflexible units that are not able to respond to the price signals by dispatching down when wholesale prices drop below short-run operating costs. The capacity factors and cycling behavior of some units will be affected as well, reducing electricity generation and possibly increasing operating costs for some units. High VRE penetrations may also increase ancillary service requirements, however, and therefore may increase the market clearing prices for operating reserves, creating additional revenue opportunities for units that are able to provide these services. Increased wholesale price volatility will similarly provide signals to the market of increased value from providing flexibility to the grid.

3. Modeled Impacts of VRE on the Bulk Power System

We reviewed several studies focused on U.S.[1] that present concrete quantitative projections for how various metrics may change as more VRE is introduced into power systems, listed in Table 4. However, care must be exercised when making direct comparisons between the results of individual studies, as the studies were conducted at different times, cover different regional electricity systems, apply different scheduling and dispatch models, and use varying parameter assumptions (e.g., fuel prices, model year, load growth, unit expansion and retirement, VRE penetration, etc.). Additionally, these studies take a number of different approaches to modeling

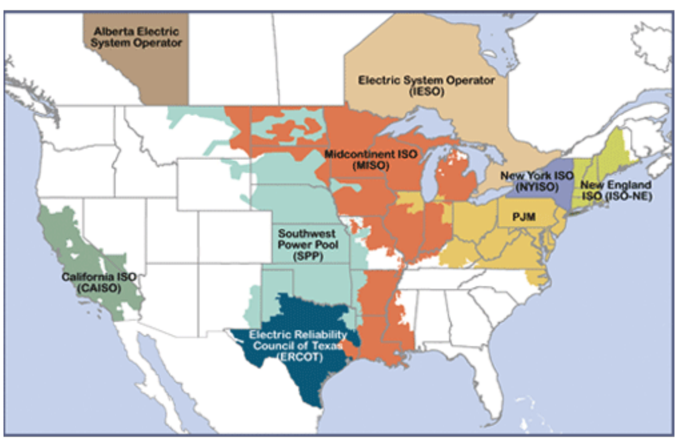
[1] There are a number of international studies that cover similar topics [14–18]. Many of the qualitative findings are similar to those reported in the U.S. literature.

system evolution in response to increasing VRE penetrations. Detailed modeling of system dispatch and market clearing prices also vary across the studies.

[Table 4 about here]

3.1. Overview of Studies

The studies cover a wide variety of different regions in the U.S. The Renewable Energy Futures Study [19] covers the entire continental U.S. while the Western Wind and Solar Integration Study (WWSIS) (Phase 2) [20] covers the Western Interconnection and the Eastern Wind Integration and Transmission Study [21] and Eastern Renewable Generation Integration Study [22] cover the Eastern Interconnection. Many of the other studies focus on particular organized wholesale markets, including studies focused on the California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), PJM Interconnection (PJM), New York Independent System Operator (NYISO), and New England Independent System Operator (ISO-NE. One study focuses on Colorado [23], a state outside of an organized wholesale market. Locations of the organized wholesale markets are illustrated in Figure 1.



Note: All regions from SPP to the east are in the Eastern Interconnection, all regions west of SPP are in the Western Interconnection, and ERCOT is part of the Texas Interconnection.
Source: FERC https://www.ferc.gov/images/maps/rto_map.gif
Figure 1. Location of ISO/RTO regions in North America.

The studies also vary in terms of the mix of variable renewables considered in the scenarios. Many focus exclusively on wind energy, including some scenarios with offshore wind. Others include a mix of wind and solar, particularly in more recent studies or studies that cover regions with high solar resource quality like the southwestern U.S. None of the studies focus exclusively on solar.

The studies focus on a variety of questions related to integrating VRE into power system operations and markets. Several studies focused on the technical and physical barriers to operating the grid with high levels of VRE [19,21,22,24]. The WWSIS [24] identified several changes to integrate 30% wind and 5% solar including increased balancing area cooperation, implementation of sub-hourly scheduling, and expansion of transmission infrastructure as appropriate. Studies focused on particular ISOs often considered both operational impacts and market impacts of high shares of VRE [25–27]. Other studies focused on more specific questions, such as impacts of VRE on revenue sufficiency [28–30], the market value of renewables at high penetration levels [31,32], the costs of thermal plant cycling [20], impacts to ancillary service prices [23,27], and the impact of various solar plant configurations [33].

All of the studies model the dispatch of generation, but they differ in how they treat decisions to invest in or retire generation capacity. The reviewed studies are broadly segmented into two general categories based on the modeling approach:

- Studies that fix the capacity of the existing generation fleet irrespective of the introduction of new VRE capacity into the system
- Studies that use capacity expansion models or assumptions to define investment and retirement of thermal units for each scenario of VRE capacity

Studies with fixed thermal expansion just use tools that simulate the dispatch of power systems. Studies that vary investment or retirement decisions for each scenario of VRE capacity often also use capacity expansion models in addition to more detailed grid dispatch tools. The Eastern Wind Integration and Transmission Study (EWITS) [21], for example, examined used the Electric Generation Expansion Analysis System (EGEAS) capacity expansion model from the Electric Power Research Institute (EPRI) to conduct a regional capacity expansion analysis for each wind scenario. Each scenario was then examined in more detail using the PROMOD production cost model to identify technical and physical barriers to operating the grid with high levels of wind generation.

In contrast to this two-step approach of building a scenario with a capacity expansion model then evaluating the scenario with a production cost model, some studies use tools that tightly link the capacity expansion and dispatch. Levin and Botterud [29], for example, developed a new modeling framework to determine the least-cost thermal unit expansion, hourly commitment and dispatch of energy and ancillary services in a power system. They applied the model to a case study of a simplified 'ERCOT-like' system that bundles thermal generators into four unit types: nuclear, coal, natural gas combined-cycle, and natural gas combustion turbines. They examined the impacts to generation expansion, energy prices, ancillary services prices, and thermal unit revenue sufficiency that would result under 10% (baseline), 20%, 30%, and 40% wind generation. Bistline [32] and Mills and Wiser [31] similarly developed models that simultaneously solve investment and dispatch for cases with high shares of variable renewables.

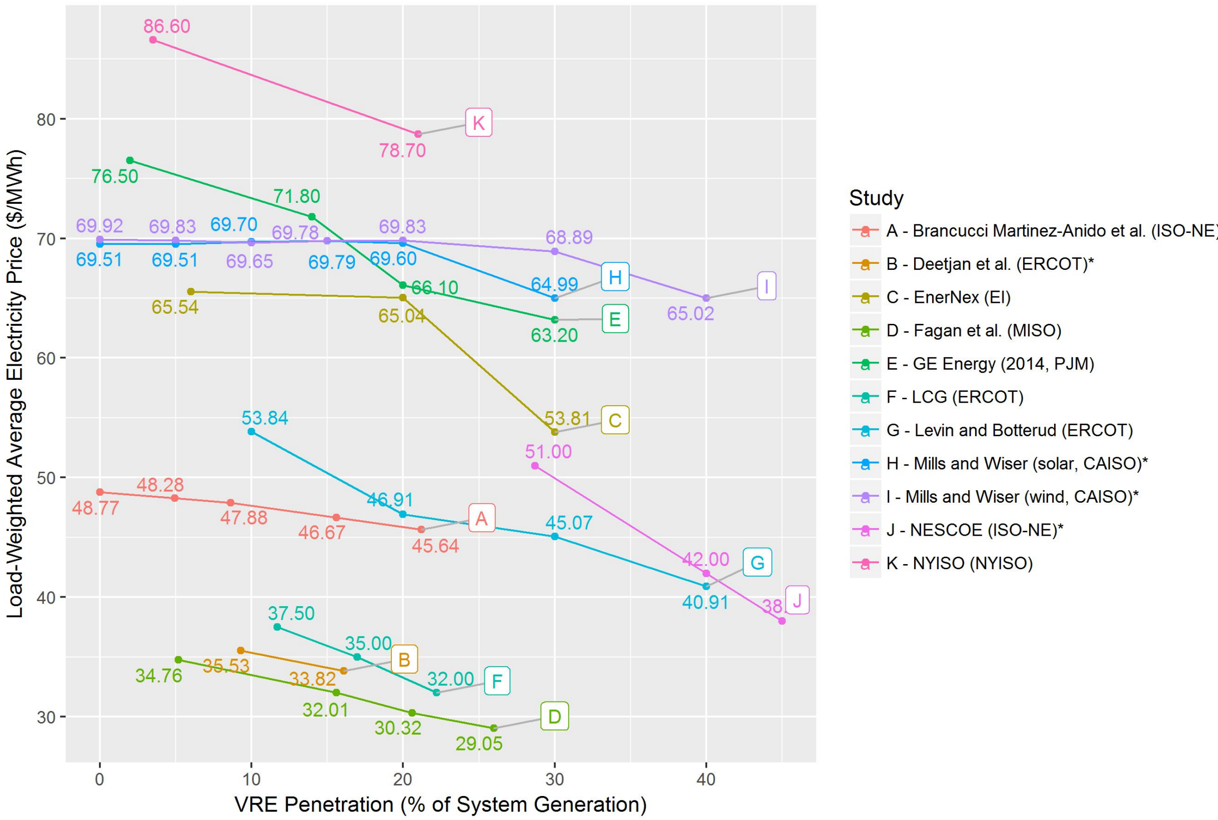
All of the studies described above establish fixed VRE targets and analyze how the system may respond to integrate those particular levels of renewable penetration. In contrast to those studies, Shavel et al. [34] presented a model that optimizes investments in all new generation capacity (wind, solar, and thermal) in the ERCOT system in response to various parameter sensitivities, e.g. natural gas prices, renewable technology costs, and carbon emissions regulations. Therefore, the resultant VRE penetrations in each of six different scenarios are determined endogenously by the model itself, as with all other types of generation in order to minimize costs.

Note that all of the studies, with the exception of the last one, impose VRE exogenously. Moreover, they assume a substantial amount of existing resources, which are not adapted to a high VRE resource mix. Since it may take decades for the resource portfolio to fully adapt, and also since retirement decisions are not considered in all the studies, the resulting generation mix will likely deviate from what would emerge from a greenfield long-run equilibrium analysis. The results should be interpreted accordingly.

3.2. Impacts to Wholesale Energy Prices

Despite the different methodological approaches and the range of parameter assumptions applied, there appears to be broad consensus that higher levels of VRE will result in lower average wholesale electricity prices, or LMPs (Figure 2). This trend is further highlighted in Table 1. which presents the change in average wholesale energy price that corresponds with a 1% increase in VRE penetration. These values range from -$0.80 to -$0.10/MWh across the selected studies, with an average value of -$0.37/MWh. In interpreting these results, it is important to consider that different generation technologies have different exposure to the reductions in the average price. A flexible plant will be less exposed to periods of low (or even negative) wholesale energy prices since they can dispatch down when LMPs are lower than the generator's short-run marginal operating costs. A non-hedged fully inflexible plant (whether inflexible physically, contractually, or otherwise), on the other hand, will be exposed to the full reduction in average prices because such a plant will not dispatch down even when wholesale energy prices fall below short-run operating costs. Electricity purchasers and customers, meanwhile, will benefit from these wholesale energy price reductions; note, however, that other system costs not embedded in LMPs may increase (e.g., the direct and transmission costs associated with VRE).

It is also important to keep in mind that most of the studies do not reflect long-run equilibrium conditions, but rather systems where the generation portfolio has not fully adapted to the higher levels of VRE. Price formation in fully adapted systems in long-run equilibrium may therefore differ from the trends revealed in the majority of our sample of studies. In particular, studies that fix the capacity of the existing generation fleet irrespective of the introduction of new VRE capacity into the system tend to reflect short-run conditions and prices impacts.



Note: Studies denoted with an asterisk report a simple average price while the remainder report a load-weighted average price.

Figure 2. Projected Wholesale Electricity Prices with Increasing VRE Penetrations

Table 1. Relationship Between Average Wholesale Electricity Price and VRE Penetration

Study	**Change in price ($/MWh) per % increase in VRE penetration**
Brancucci Martinez-Anido et al. (ISO-NE)	-$0.15
Deetjan et al. (ERCOT)*	-$0.25
EnerNex (EI)	-$0.46
Fagan et al. (MISO)	-$0.28
GE Energy (2014, PJM)	-$0.50
LCG (ERCOT)	-$0.52
Levin and Botterud (ERCOT)	-$0.41
Mills and Wiser (solar, CAISO)*	-$0.13
Mills and Wiser (wind, CAISO)*	-$0.10
NESCOE (ISO-NE)*	-$0.80
NYISO (NYISO)	-$0.45

3.3. Impacts to Operating Reserve Prices

While the impacts of high VRE penetrations on wholesale energy prices have been studied in some detail, the impacts on prices for operating reserves[2] are generally not as well understood; this is the case for a number of reasons. Reserve markets are much smaller than energy markets in terms of total value. Reserve markets have also been introduced more recently than energy markets, are less uniform across different ISOs, and their market rules have been adjusted frequently over the past decade, making it more difficult to isolate the primary drivers of price impacts. Hence, modeling reserves markets is more challenging than energy markets. However, as VRE penetrations increase, ancillary service (AS) markets may serve as a mechanism for monetizing a portion of the value of flexibility in power systems, thereby providing an increasingly important revenue stream for flexible generating units.

In the wholesale energy market, low marginal cost VREs influence prices (i.e., LMPs) directly from the supply-side, by providing generation at low (or negative) marginal cost, which most studies indicate lead to lower market clearing prices in the short term (Figure 2). In contrast to the energy market, however, VREs have not typically supplied operating reserves themselves, at least historically, and therefore do not necessarily directly affect the market from the *supply-side*.[3] Because some generators can provide both energy and operating reserves, energy market prices and operating reserve prices are indirectly related though opportunity costs [35]. Influences of VRE on energy market prices can therefore indirectly affect the market prices for operating reserves on the supply-side, though the effect is ambiguous. Additions of VRE can free up other generation to provide operating reserve instead of energy, lowering reserve prices. Or additions of VRE can lower energy prices and increase the opportunity cost of a generator that has to be online and producing energy in order to provide reserves, increasing reserve prices.

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[2] We focus primarily on the operating reserves that are typically procured through market mechanisms in the United States, i.e., regulation and contingency reserves.

[3] This has historically been the case due to a combination of technical limitations, market rules that prevent participation, economic opportunity costs that may limit voluntary participation, and VRE generation incentives that are foregone by units while they provide reserves. However, VREs may begin to provide more operating reserves as penetration levels increase. VRE has the technical capacity to provide downward spinning reserves under most system conditions, and also upward spinning reserves under certain system conditions (e.g., if the VRE generator is currently being curtailed).

Another impact of VREs on reserves prices is introduced through increased *demand* for these services. The impact of VREs on reserve prices is felt on the *demand-side*, as higher VRE penetrations will likely require greater AS quantities to balance the increasing overall variability and uncertainty in the system in order to maintain system reliability within given reliability standards, thereby also driving up AS prices. This is particularly the case with regulation reserves, which are typically procured hourly through day-ahead and/or real-time markets. Resources that participate in the regulation reserve market must be able to adjust their generation output level in response to automatic generation control signals that are sent roughly every four seconds, or less in the case of fast-frequency response signals that are being implemented in some markets. As VRE penetrations increase so too will short-term net load variability, and greater quantities of regulation reserves will be required to ensure that supply and demand are balanced in real-time; this increased demand for regulation reserves may tend to increase prices for the service.[4]

For example, an analysis of 30% VRE penetration in PJM found that an additional annual average of 1,000 MW to 1,500 MW of regulation reserves would be required to maintain system reliability; on the other hand, no additional spinning or non-spinning reserves would be required [26]. Hummon et al. [23] calculated hourly regulation requirements based on the statistical variability of load, wind, and solar generation, while Mills and Wiser [31] assumed the regulation requirement to be 2% of hourly load plus 5% of the day-ahead wind or solar forecast. Both of these latter studies assumed that contingency reserve requirements are independent of VRE penetration; these requirements are instead impacted by the possibility of large generator or transmission outages. This assumption reveals a more-general truth: VRE is not alone in impacting reserve needs and markets, as inflexible baseload units also must be complemented by more flexible units that are able to follow load and provide operating and contingency reserves; in other words, the amount and nature of AS requirements may vary based on technology, but various reserves are required for all generation types [36,37].

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[4] Historical experience with managing growing shares of VRE demonstrates that market reforms and improvements to VRE forecasts can actually lead to reductions in reserves as VRE are added [35], though studies tend to focus on the effect of VRE on reserves keeping all else constant.

Reserve requirements are set administratively and therefore a primary challenge of modeling the AS markets is that prices are typically largely dependent on administratively determined parameters, such as hourly AS requirements, scarcity pricing rules, or in the case of ERCOT, the shape of the operating reserve demand curves. Therefore, while it is possible to model market outcomes under different assumed future scenarios, it is difficult to predict how market design will evolve in the long term to accommodate changes in the bulk power system. Moreover, the costs of providing reserves, which consist partly of opportunity costs from not providing services in other markets (e.g., energy in the energy market), is complex to estimate, adding to the reserve market modeling challenge.

Due in part to the complexities described above, there are relatively few studies that reported reserve prices. The results of the relevant studies reviewed here are summarized in Figure 3 and Figure 4. Overall, the picture is not as clear as for energy prices. There is a general trend of increasing prices for regulation with higher VRE penetrations. The picture for spinning and non-spinning reserves is somewhat less clear, with studies showing a combination of relatively stable or increasing reserve prices with the VRE level. Overall, it is difficult to draw any strong conclusions from this sample.

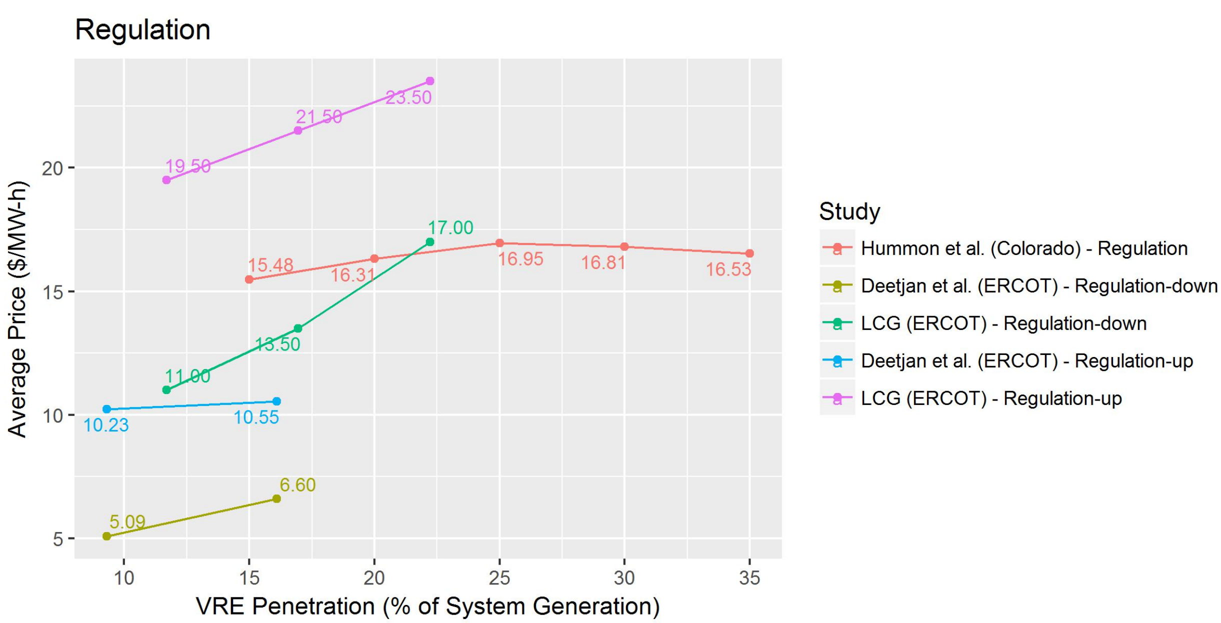


Figure 3. Projected Prices for Frequency Regulation Reserve with Increasing VRE Penetrations

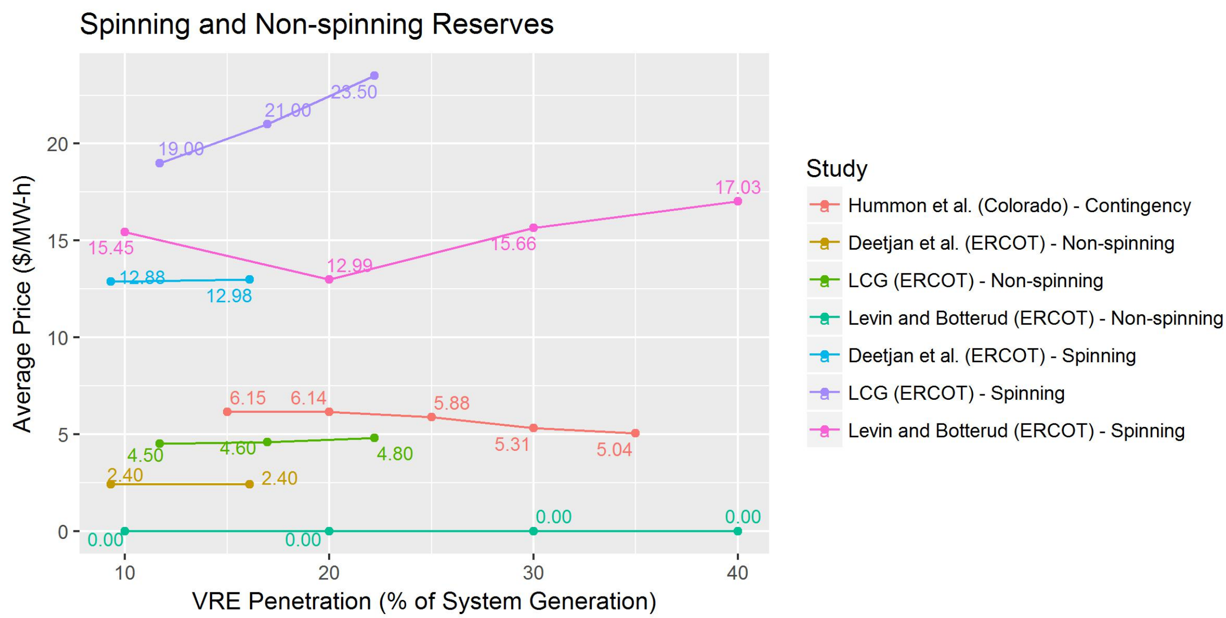


Figure 4. Projected Prices for Spinning and Non-Spinning Reserves with Increasing VRE Penetrations

3.4. System Dispatch, Thermal-Plant Capacity Factors, and Cycling Costs

The overall dispatch of the power system changes as VRE penetrations increase. Since VREs enter at the lowest marginal cost end of the merit-order dispatch curve, other technologies with higher marginal costs tend to be dispatched less. The capacity factors of thermal generators will therefore tend to decrease, as summarized in Figure 5 through Figure 7. Note that most studies assumed that nuclear units are inflexible and therefore their capacity factors either do not change significantly or are not explicitly analyzed.

This effect will be particularly pronounced if VREs are added on top of existing generation resources, leading to a surplus of available capacity. In the longer run, the generation portfolio of the system is likely to settle around an equilibrium solution where the mix of generation shifts toward resources with lower fixed costs and VREs replace some of the existing generation resources, with the degree of displacement affected by the capacity credit of VRE as well as any policy or regulatory decisions that speed or slow the transition. Still, since the capacity credit of VREs is lower than that of thermal units, especially at higher penetrations, the level of displaced capacity will not be as significant as the amount of added VRE. Hence, the capacity factors of the remaining dispatchable generation technologies are likely to decrease, on average, though the increased need for system flexibility may mitigate these declines for some specific plant types.

Another potential consequence of increasing VRE levels is that dispatchable units may have to cycle more often. Some studies have examined how increased VRE penetrations will impact the cycling of thermal units and the corresponding costs that may be incurred, Figure 8; in restructured markets, altered wholesale energy price patterns and increases in AS needs and prices may—to a degree, at least—compensate dispatchable units for these increased cycling demands.

There are several specific reasons for cycling-related cost increases. First, thermal unit ramping—i.e., adjusting generation output—typically causes some mechanical fatigue and may therefore increase long-term maintenance costs. Second, unit startups and shutdowns cause similar unit fatigue, and units also incur additional fuel costs for startups. GE Energy [26] found that natural gas combined-cycle units were the most significantly affected due to increased startup and shutdown requirements. The cycling costs of natural gas combustion turbines (CTs) were found to decrease at higher VRE levels due to overall decreases in generation from those plants. These costs can be exacerbated by longer idle times that require warm or cold starts, as opposed to hot starts. Finally, units may be operated more frequently at lower output levels, which typically means that the operational efficiency is lower with a corresponding increase in fuel use and variable generation costs. These latter costs are generally not included in cycling cost calculations, and are instead embedded in the estimated impacts of VRE on system production costs; as such, we do not report these results here.

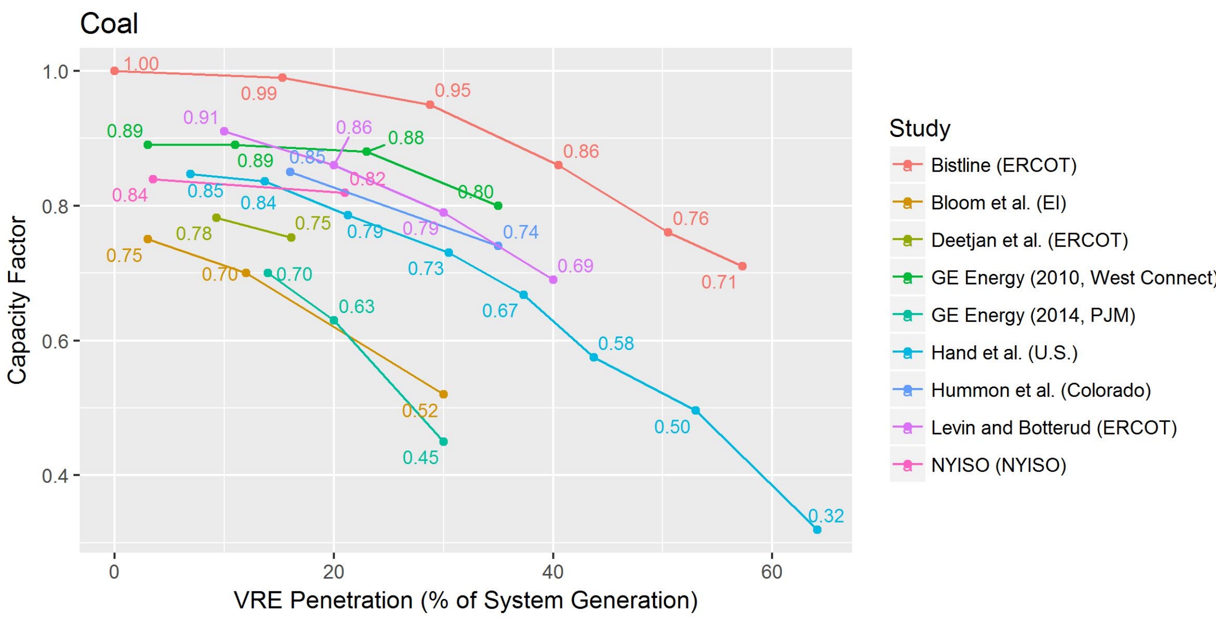


Figure 5. Capacity Factors for Coal Plants with Increasing VRE Penetrations

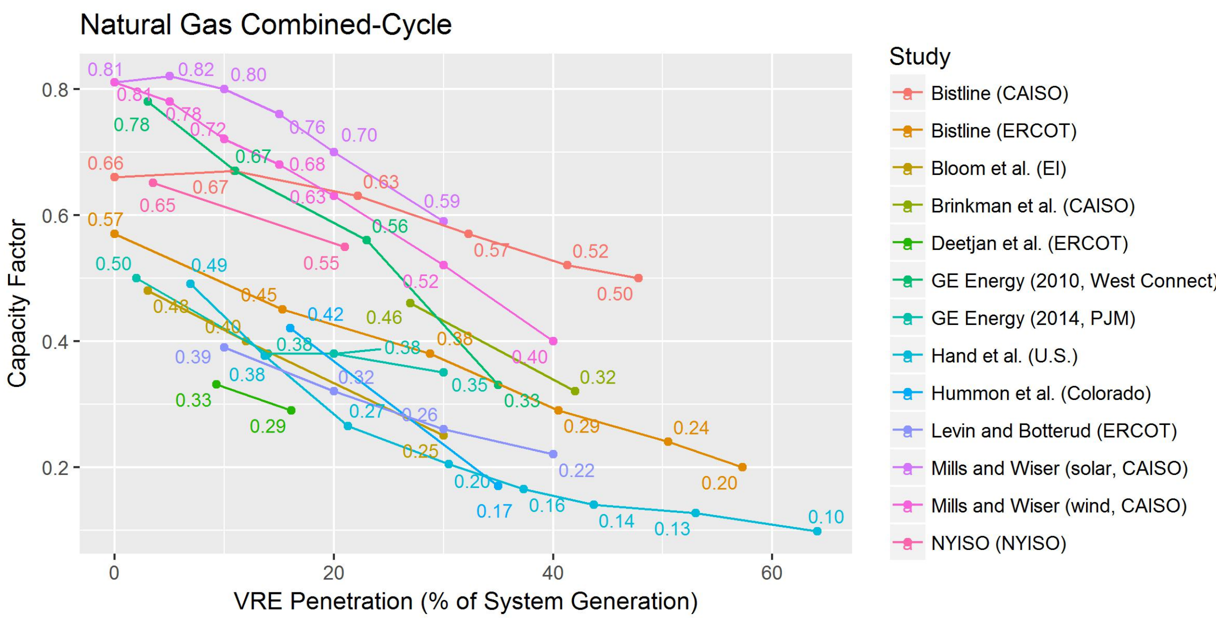


Figure 6. Capacity Factors for Natural Gas Combined-Cycle Plants with Increasing VRE Penetrations

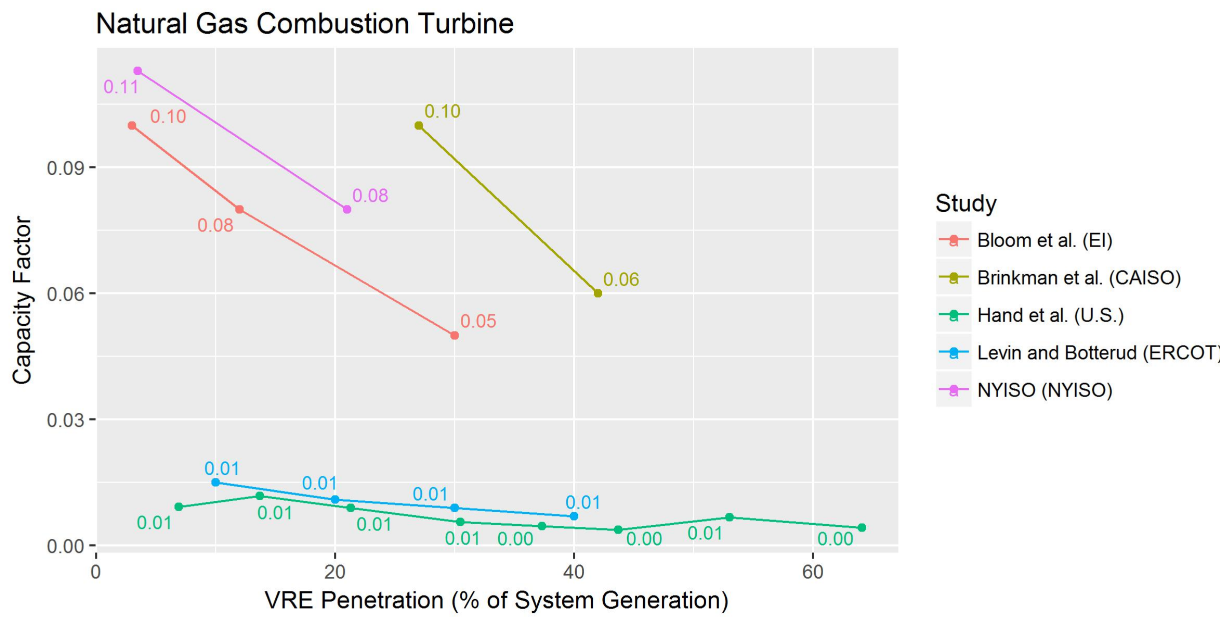


Figure 7. Capacity Factors for Natural Gas Combustion Turbine Plants with Increasing VRE Penetrations

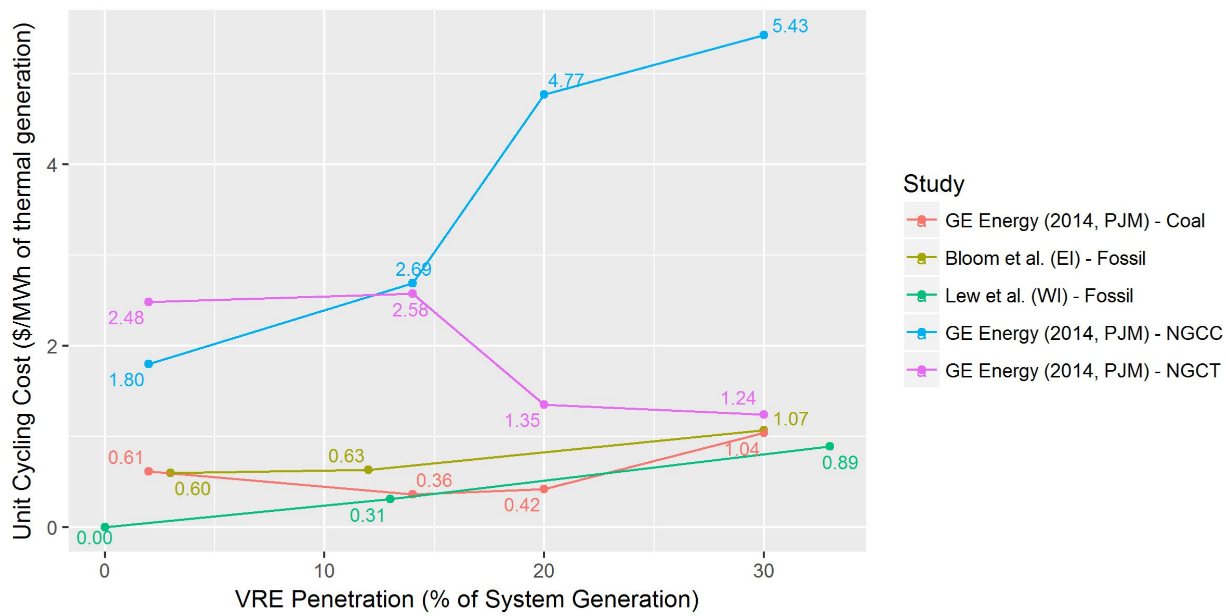


Figure 8. Cycling Costs for Thermal Plants with Increasing VRE Penetrations

3.5. Revenues and Operating Profits for Generators

Revenue impacts originate from changes in wholesale prices (which influence the revenues received for each unit of generation) as well as changes in capacity factors (which influence the total quantity of generation a plant is able to sell into the market). Some studies focused on projected plant revenues and profits to anticipate plant types that may be at-risk for retirement, but did not explicitly consider such unit retirements in their modeling. As plant retirements decrease generation supply, these would likely have an upward influence on price and profitability for the remaining units in the long term. Not all studies considered this longer-term dynamic, and the results should be interpreted accordingly.

In restructured markets, most generators receive the majority of their revenues through wholesale energy markets (see the various ISO/RTO market monitoring reports, e.g., [38–43]. Reserve markets have delivered additional revenue to some generators, but generally in small quantities. That said, reserve markets may play an increasingly important role for some units as VRE penetration increases and as the demand for these services grow. In some regions, capacity markets (or requirements that lead to bilateral capacity contracts) provide additional revenue to encourage resource adequacy, whereas in others (e.g., ERCOT) it is presumed that energy-market prices will embed compensation for capacity during scarcity events. Regardless of the details, the important point for this review is that revenues from AS and capacity markets/contracts were not included in all studies, and so results should be interpreted with some caution. Note, finally, that all reviewed studies simulated the operation of a restructured wholesale market; power plants in regions that lack such markets or that have physical or financial contracts that hedge against wholesale market price variations may be—at least partially—immune from immediate revenue impacts as signaled by wholesale market prices and dynamics.

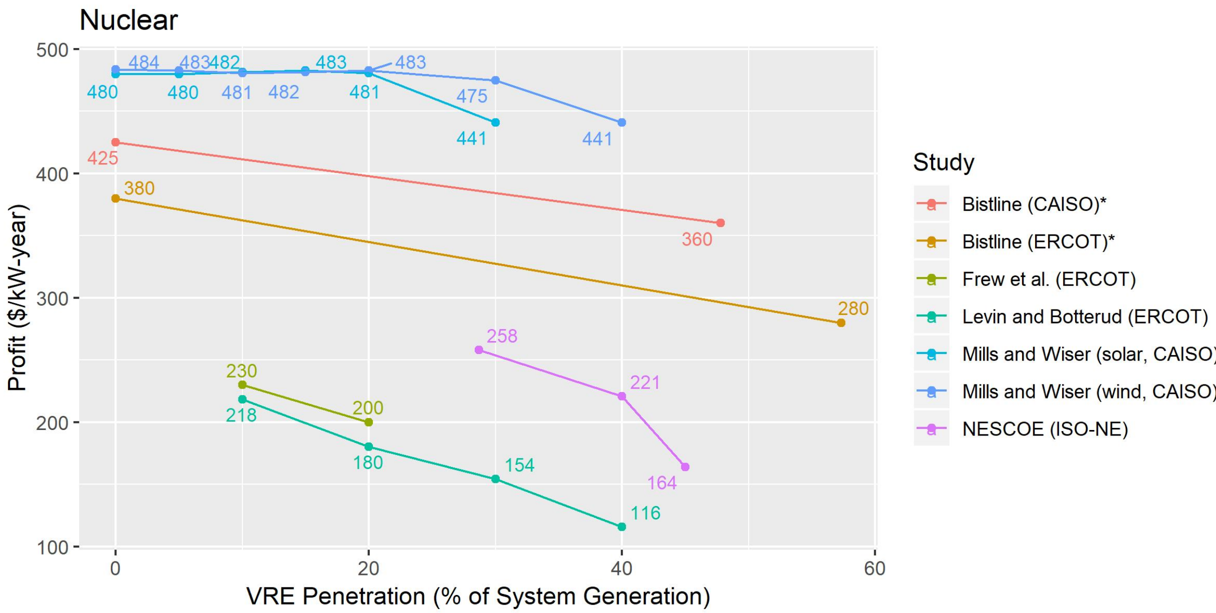
Figure 9 through Figure 12 summarize the reported impacts on operating revenues and profits for nuclear, coal, natural gas combined-cycle and CT plants. Studies differed in how they report revenues and profits: some strictly presented plant revenues, while others presented operating profits (i.e., revenues less operating costs but not considering capital costs). Table 2 indicates which cost and revenue streams were considered by each study. The studies that reported revenues (i.e., absent of operating costs) are also identified in the figure legend with a star, while the remainder reported operating profits. As indicated in Table 2, none of the studies considered capital costs. Overall, it should be stressed, once again, that it is more appropriate to analyze these figures for the trends that are identified within each individual study, as opposed to making comparisons of the specific values identified across different studies.

Table 2. Revenue and Cost Streams Included in the Revenue Analysis Presented by Each Study

Study	**Energy Market Revenue**	**AS Market Revenue**	**Capacity Market Revenue**	**Operating Costs**	**Capital Costs**
Bistline (CAISO and ERCOT)	X		n/a		
Frew et al. (ERCOT)	X	X	n/a	X	
GE Energy, 2010 (ERCOT)	X		n/a		
Levin and Botterud (ERCOT)	X	X	n/a	X	
Mills and Wiser (CAISO)	X	X	n/a	X	
NESCOE (ISO-NE)	X		X	X	
Shavel et al. (ERCOT)	X	X	n/a	X	

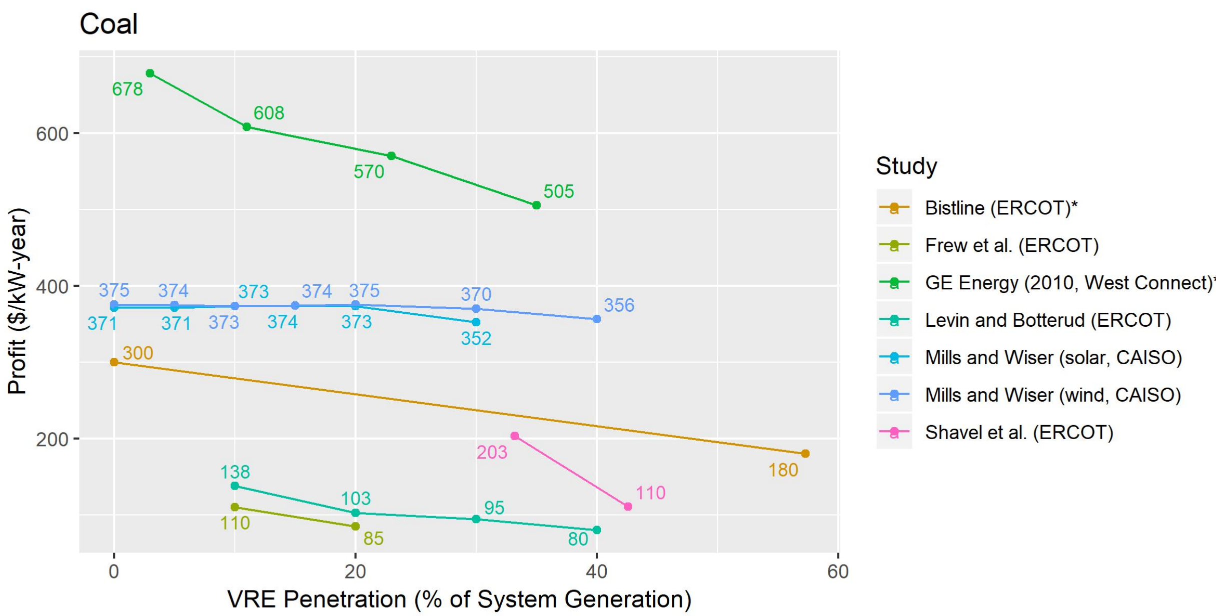
Note: Several of these studies embed capacity compensation in energy-market prices (e.g., through assumptions about scarcity pricing), even if capacity markets are not separately modeled.

Overall, these studies show a downward sloping trend in revenue and operating profits for nuclear and coal plants as VRE penetrations increase. Natural gas fired generation tends to see a reduction in revenue with increasing VRE penetration but operating profits are generally less-affected. This is partly because operating costs are largely variable in nature—any reductions in total generation output also significantly reduce fuel costs. Those studies that assessed long-term equilibrium effects on profitability sometimes found that flexible gas plants fare reasonably well under higher VRE penetrations, at least in terms of operating profit: natural gas fired generation tends to be a competitive option with low fixed costs and low gas prices, and gas units are flexible and therefore tend to benefit from price spikes and to be less exposed to average price reductions compared to nuclear and coal generation. Note that GE Energy [24] assumed a relatively high natural gas price ($9.50/MMbtu), and also included a $30/ton cost of carbon. This leads to higher reported energy prices and correspondingly higher revenues than reported by other studies.



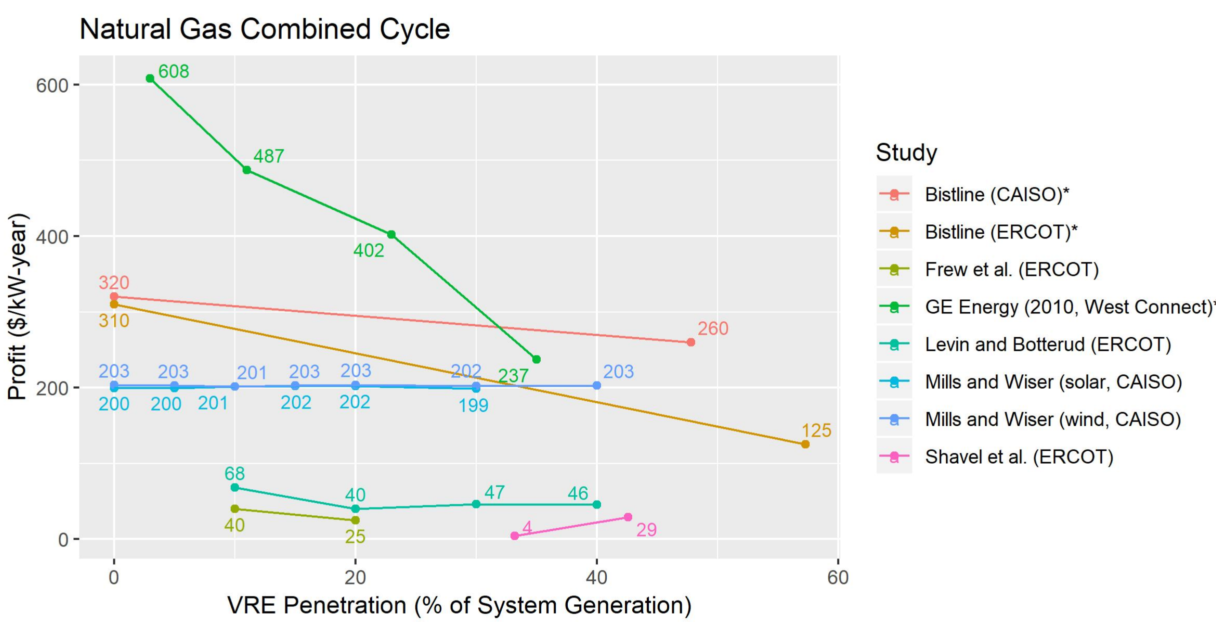
Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 9. Operating Profits and Revenues for Nuclear Plants with Increasing VRE Penetrations



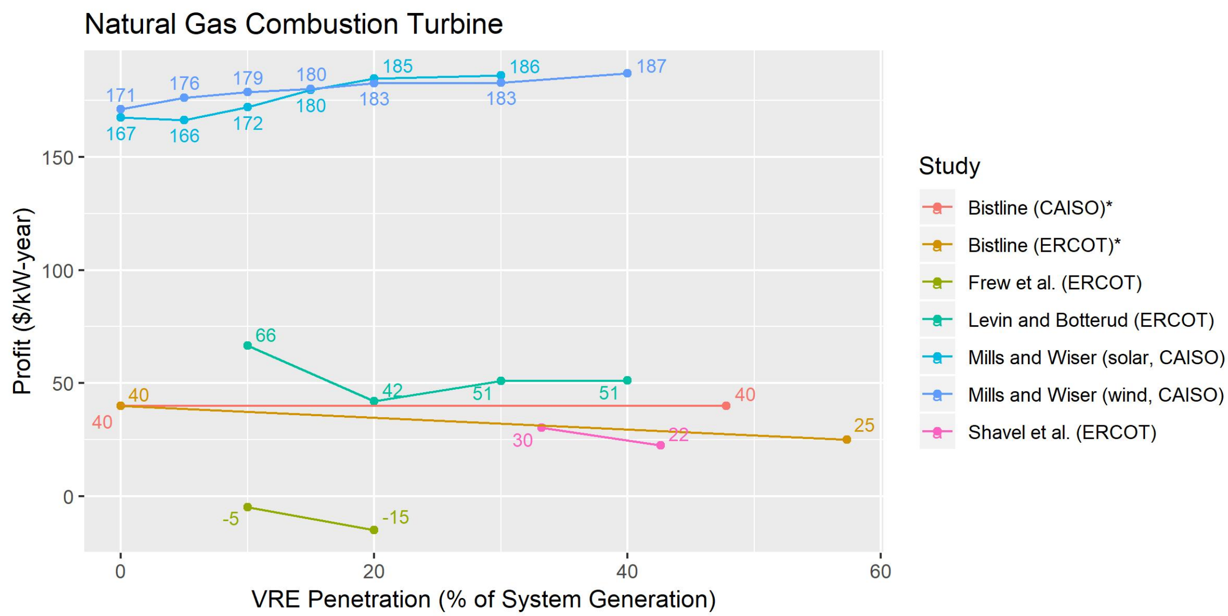
Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 10. Operating Profits and Revenues for Coal Plants with Increasing VRE Penetrations



Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 11. Operating Profits and Revenues for Natural Gas Combined-Cycle Plants with Increasing VRE Penetrations



Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 12. Operating Profits and Revenues for Natural Gas Combustion Turbine Plants with Increasing VRE Penetrations

3.6. Impact of Natural Gas Prices and VRE Incentives

While it has been shown that increasing VRE penetrations may cause wholesale electricity prices to decline, the price of natural gas is another primary driver of electricity prices.

Levin and Botterud [29] found a price reduction of 23% when the natural gas fuel price is reduced from its baseline value of $5.15/MMbtu to $3.00/MMbtu, comparable to the price reduction when wind penetration was increased from 10% to 40%. GE Energy [26] found that reducing natural gas prices from the baseline assumption of $8.02/MMbtu to $6.50/MMbtu lead to a price reduction of 7.4%, comparable to increasing VRE from 2% to 14%. The reference scenario presented by Shavel et al. [34] assumed lower natural gas prices (roughly $5.80/MMbtu vs. $7.50/MMbtu) and higher renewable costs than those assumed in the high renewable sensitivity scenarios. Reducing the natural gas price and increasing renewable costs has two primary impacts in this equilibrium analysis with endogenously determined VRE penetration. First, there is substantially less wind and solar generation—accounting for 7% of the system total compared to 33%. All else equal, previous evidence suggests that wholesale electricity prices (i.e., LMPs) should increase as a result of the reduced VRE generation. Second, natural gas prices are also lower in this case and this has a downward impact on electricity prices. The combined effect is an overall decrease in average wholesale prices from approximately $58/MWh to $46/MWh. This suggest that in a long-run equilibrium setting, reducing natural gas prices will likely also reduce electricity prices, even if VRE generation is simultaneously reduced as well.

Finally, Levin and Botterud [29] analyzed the system impacts of removing the federal PTC for wind generation, isolating the bidding impact of the PTC from its deployment effect (i.e., the wind penetration level was independent of the PTC assumption). In the base cases, wind generators were assumed to receive a $23/MWh tax credit. The study found that removing the PTC, but keeping wind penetration constant, does not influence electricity prices at 10% wind penetration, as wind never provides the marginal unit of generation under these conditions. At 20% and higher wind penetration levels, on the other hand, the study did observe price impacts driven by the bidding impacts of wind power. The study found that removing the PTC increases the load-weighted average electricity price by 0.3%, 2.2% and 10.4% for 20%, 30% and 40% wind penetration respectively. This effect is still small compared to the impact of changes in natural gas prices.

4. Observed Impacts of VRE on the Bulk Power System

Here we turn our focus to historical empirical observations of the impact of VRE on wholesale market prices and generation assets by reviewing literature, analyzing wholesale market data, and utilizing simple power market models. In particular, we assess impacts to average annual wholesale prices, impacts to wholesale price variability with a focus on negative prices, and the relationship between VRE and recent power plant retirements.

We focus on selected major electricity-trading hubs in ISOs identified by the U.S. Energy Information Administration (EIA)[5] (Figure 13), along with our own choice of hubs not listed by EIA (SPP South near Oklahoma City in SPP and Zone G near the Hudson Valley in NYISO).

[5] http://www.eia.gov/electricity /wholesale/

We then place additional attention on specific ‘constrained’ pricing points. For the most part, we summarize hourly-averages of real-time (RT) prices, as reported in ABB’s Velocity Suite [44].

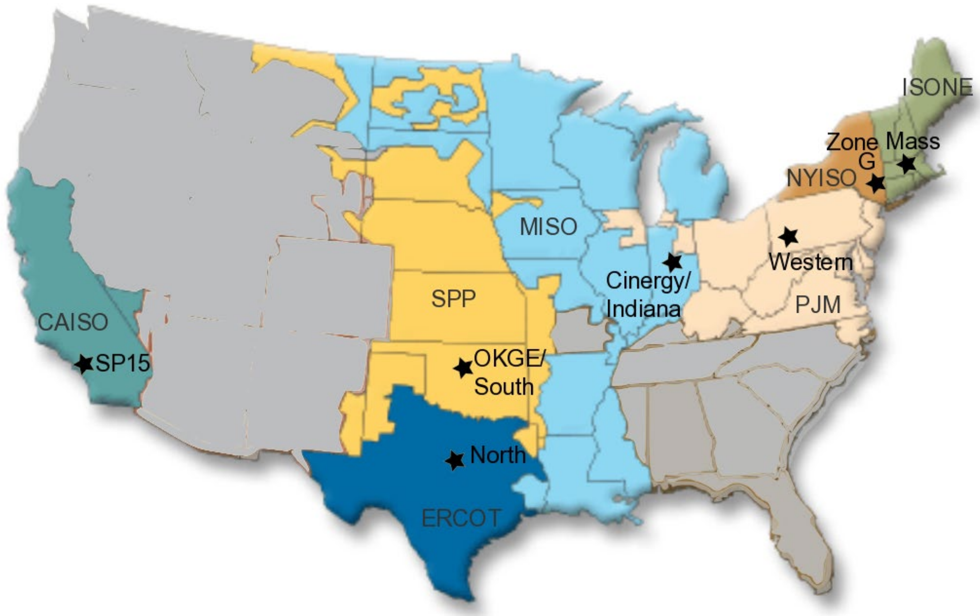


Figure 13. Locations for a Portion of the Selected Electricity Pricing Points Investigated in this Analysis

4.1. Impacts on Average Annual Historical Wholesale Electricity Prices

Several studies have used historical observations or simple models to estimate the impact of VRE on wholesale prices for different regions of the U.S. [45–52], summarized in Table 3. For most studies, we report the effect of VRE as the decrease in the average RT wholesale price with the average amount of VRE over the study period, relative to the average price without the VRE; in two cases, however, the estimates represent the reduction in wholesale prices over time due to total growth in VRE. Where available, we also report the VRE penetration as the average VRE over the period relative to the average demand over the period. The empirically estimated reduction in average wholesale electricity prices from wind and solar range from $0-8.9/MWh, depending on the region, the time period of the analysis, the VRE technology and its level of penetration, and the study. A study focused on ERCOT finds higher merit order effects in the wind-rich West Texas region, where transmission constraints led to reduced and negative prices before Competitive Renewable Energy Zones (CREZ) transmission assets were completed in 2013 [53].

Table 3. Average Wholesale Price Reduction Associated with VRE Growth

Study	Applicable Region	Time Period	Average VRE Penetration (% of demand)	Decrease in Average Wholesale Price from Average VRE
Woo et al. 2011	ERCOT	2007-2010	Wind: 5.1%	Wind: $2.7/MWh (ERCOT North) $6.8/MWh (ERCOT West)
Woo et al. 2013	Pacific NW (Mid-C)	2006-2012	N/A	Wind: $3.9/MWh
Woo et al. 2014	CAISO (SP15)	2010-2012	Wind: 3.4% Solar: 0.6%	Wind: $8.9/MWh Solar: $1.2/MWh
Woo et al. 2016	CAISO (SP15)	2012-2015	Wind: 4.3% Solar: 2.6%	Wind: $7.7/MWh Solar: $2.1/MWh
Gil and Jin 2013	PJM	2010	Wind: 1.3%	Wind: $5.3/MWh
Wiser et al. 2016[a]	Various regions	2013	RPS energy: 0%-16% depending on the region	RPS energy: $0 to $4.6/MWh depending on the region
Jenkins 2017[b]	PJM	2008-2016	N/A	Wind: $1-2.5/MWh
Haratyk 2017[b]	Midwest Mid-Atlantic	2008-2015 2008-2015	N/A	Wind: $4.6/MWh Wind: $0/MWh

Notes: a – Price effect is estimated impact of RPS energy relative to price without RPS energy in 2013 before making adjustments due to the decay effect discussed by the authors. b – Decrease in average wholesale price is based on change in wind energy from 2008-2016 (Jenkins 2017) or 2008-2015 (Haratyk 2017), rather than the decrease from average wind reported in other rows.

Additional studies[4,7,54], sometimes using more stylized and/or partial assessments, are not included in the table above.

This sample of U.S. focused studies is a subset of a much broader literature of similar analyses of the price effect of wind and solar in Europe, with many of the studies summarized by [15,55,56].

The range of the merit order effect in Table 3 is within the range of results for wind and solar in European countries as summarized in [15].

Growth in VRE, of course, is not the only factor affecting average wholesale prices. We use a simple fundamental merit order model to quantify the contribution of different factors to the observed decline in wholesale prices between 2008 and 2016 for the CAISO, a region with recent growth in both utility-scale and distributed solar, and ERCOT, a region with significant growth in wind (Figure 14). We select these two regions for two primary reasons: (1) they represent regions with among the highest shares of VRE, and (2) as single-state ISOs, they are relatively easier to model than multi-state markets.

The simple fundamental model uses a merit-order supply curve based on individual generator capacity and marginal costs along with hourly observed demand and VRE production to estimate hourly prices. Following generally similar approaches used to explain the decrease in wholesale prices in Germany [56–58][6] as well as in the Midwest and Mid-Atlantic [52], we isolate the impact of each individual factor on the decline in wholesale prices by holding all factors from 2016 fixed except for one that is changed from its 2016 value to its 2008 value. For example, we estimate the impact of growing amounts of renewable energy by changing the renewable electricity supply from its 2016 value to its 2008 value, while keeping other factors constant at their 2016 levels. Green bars represent the estimated magnitude of each factor that contributed to a decline in wholesale prices between 2008 and 2016, whereas red bars represent factors that mitigated the price decline over the same period.

Even with the many simplifications used to model wholesale power prices in this way, the supply curve model is able to reasonably match the 2008 and 2016 observed average wholesale prices in CAISO and ERCOT (see the comparison between the black markers and the blue bars in the figure). The model does not, however, replicate the hour-to-hour variability in prices since it ignores transmission constraints, operating limits on thermal generators, negative price bids from

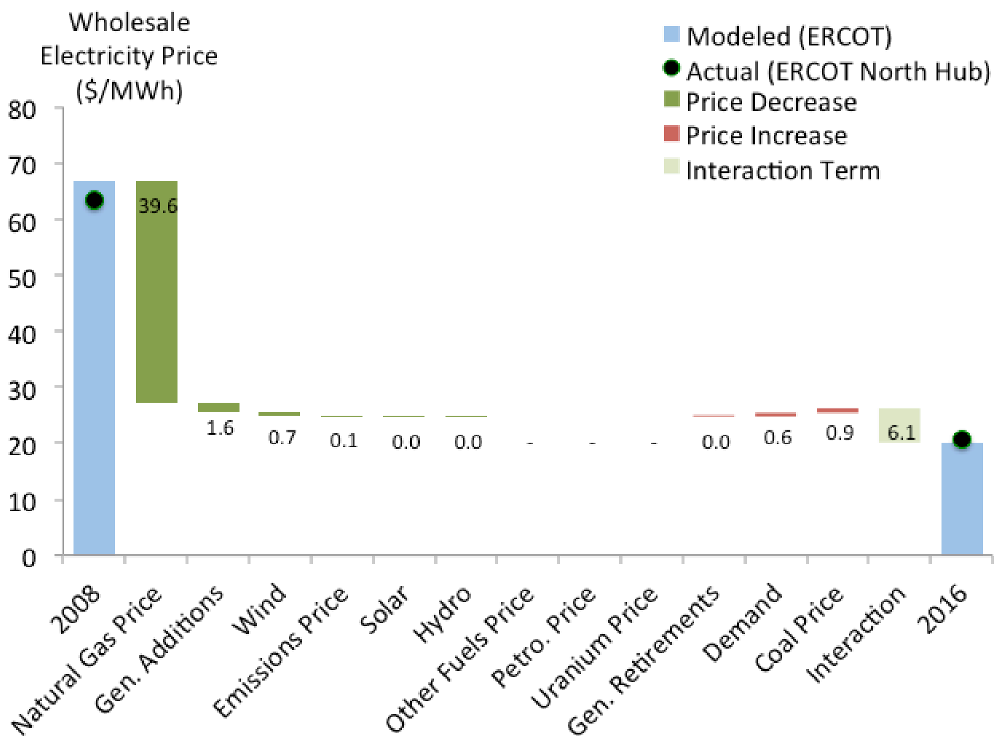
[6] Somewhat more-stylized and partials attempts to conduct similar analysis in various regions of the United States can be found in: [4,7,54].

VRE, etc.; related, by only exploring market-wide averages, the model is not able to assess geographic variations in pricing as might be caused by transmission congestion.

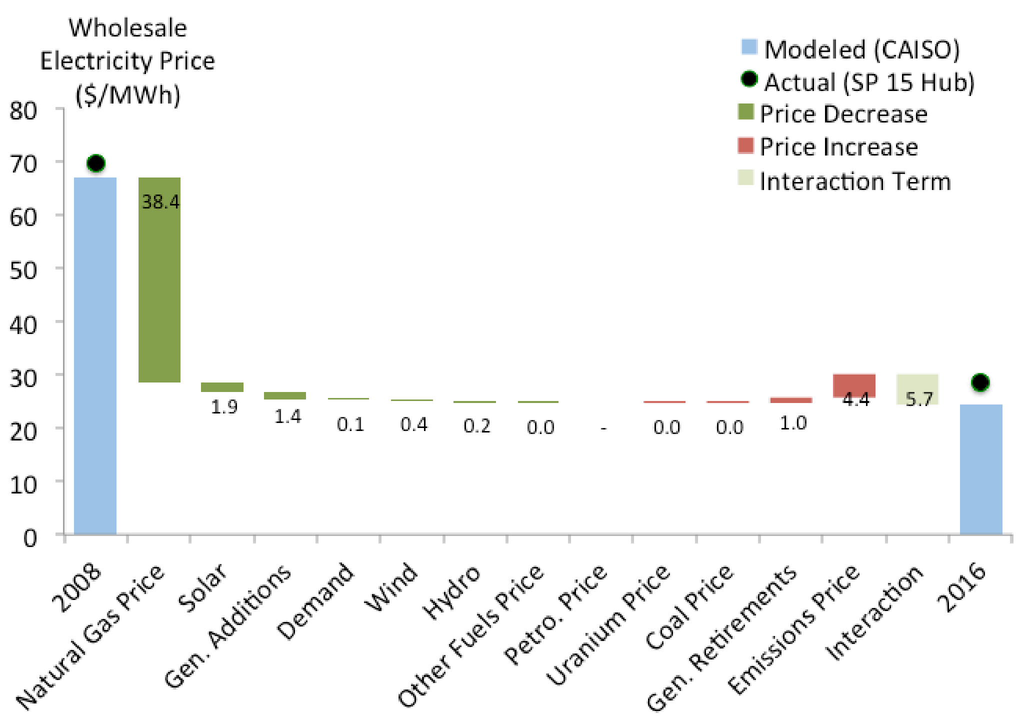
With those caveats in mind, we do see clear evidence that the primary driver of the decline in average wholesale electricity prices between 2008 and 2016 in ERCOT and CAISO is the decline in natural gas prices. We find that growth in VRE generation contributed less than 5% to the overall price decline, whereas natural gas price reductions contributed 85-90% of the overall decline in wholesale electricity prices in these markets. Other factors considered in the model include: other types of generation additions (typically natural gas); changes in emissions allowance prices; changes in coal, oil, uranium, and other fuel prices; generation unit retirements; changes in electricity load; and variations in hydropower output. The 'interaction' term, meanwhile, represents the difference between the 2008 and 2016 modeled wholesale prices that this method was not able to attribute to individual factors due to interactions between multiple factors. For example, we show the impact of VRE and natural gas when changed individually, but they likely have a different impact when changed simultaneously. In summary, these various additional factors also individually contribute to accelerating or mitigating the overall price decline in ERCOT and CAISO, but, as with VRE, all are minor contributors compared to natural gas price shifts.

These findings are consistent with recent analysis focused on wholesale prices affecting nuclear plants in Illinois. In particular, using statistical techniques, Jenkins [51] estimates the drivers for wholesale price reductions from 2008 through 2016, finding that the decline in natural gas prices was the dominant factor, resulting in wholesale price reductions of roughly $20/MWh (42-43% reduction). Growth of wind in MISO and PJM was found to have a much smaller effect of ~$1-2.5/MWh (2-5% reduction). Haratyk [52], meanwhile, estimates the drivers for wholesale price reductions from 2008 to 2015 in the Midwest and Mid-Atlantic regions, finding that natural gas price declines and load reductions were the two dominant drivers with growth in wind playing a relatively smaller role.

ERCOT



CAISO



Note: 2016 used as the base year.

Source: LBNL analysis using simple supply curve model and data from ABB Velocity Suite [44], EIA, and assumptions.

Figure 14. Estimated Contribution of Various Drivers to the Observed Decline in Average Wholesale Electricity Prices in ERCOT and CAISO

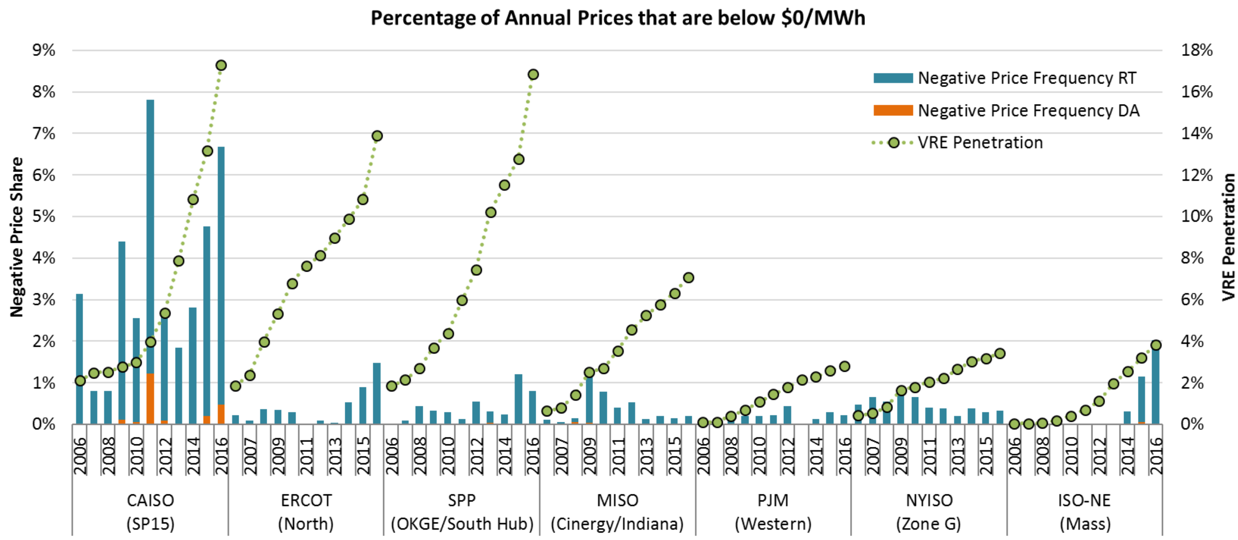
4.2. Prevalence and Impact of Negative Pricing at Selected Pricing Hubs

In addition to affecting average wholesale prices, VRE can impact wholesale price variability, which may be particularly evident by tracking the frequency of negative prices. Negative prices typically arise from surplus supply along with technical or economic constraints that prevent reductions in generation output. Transmission limitations tend to be an accelerant of negative pricing, driving prices lower in congested markets as the surplus supply is unable to find other markets to which to sell. As negative pricing is a symptom of excess supply, it is not surprising that the prevalence of negative pricing is greater during periods with lower system-wide load. The PTC and RPS programs that prioritize generation from renewable resources provide an incentive for renewable generators to continue to produce energy even when the energy price is negative. Rigid contracts that do not allow for economic curtailment yield similar results. Even market demand for ‘green energy’ yields positive prices for RECs, creating incentives for negative-price bids by VRE. Of course, VREs are not the only resources that bid negative prices in wholesale electricity markets. The lack of flexibility from existing nuclear power plants in the United States, for example, means that these plants will often bid negative prices to avoid costly shutdowns and start-ups. Fossil units (whether coal or natural gas) may also—at times—bid negative prices due to the costs of flexible operations. Even hydropower plants sometimes generate during negative-priced hours, in some cases due to run-of-river operations and in others as a result of environmental constraints. Other units may have contractual requirements that create the same incentives for negative bidding, or may be required to operate for reliability purposes regardless of market pricing. The fact that many types of power plants—at times—continue to generate power when prices at major hubs are negative is demonstrated below.

Overall, the frequency of negative prices at a select number of large electricity pricing hubs (Figure 15) indicates that negative prices in most of these hubs continue to be rare, and almost non-existent in day-ahead prices, though there is some indication of increased frequency of negative real-time prices with increasing shares of VRE resources. The SP15 hub in CAISO shows a markedly higher frequency of negative real-time prices than other hubs (6.6% in 2016, compared to 2% or less in all other selected hubs shown in the figure), and the frequency is expected to rise significantly in 2017 due to growth in VRE and high hydropower production [59]. Several initiatives in the West including expansion of the CAISO Energy Imbalance Market, potential regional expansion of CAISO to include PacifiCorp and other interested utilities, and improved coordination and utilization of transmission capacity with the Pacific Northwest may all help mitigate this increase in negative price frequency over time [59]. Even in CAISO, however, it is clear that VRE is not the only contributing factor to negative prices. The highest share of negative price hours occurred in 2011 (nearly 8% of hours in real-time market and over 1% of hours in day-ahead market), before the recent large-scale growth in solar.

Outside of CAISO, the figure suggests that recent growth in VRE may be contributing to negative real-time pricing at the selected major trading hubs in ERCOT, SPP, and perhaps in ISO-NE: in all three regions, the prevalence of negative pricing has increased recently, along with the growth in VRE, demonstrating correlation if not causation.[7] The same cannot be said for the selected major hubs in MISO, PJM, and NYISO, however. If anything, the prevalence of negative pricing in these specific hubs has declined in recent years, though other research suggests that pricing at still other hubs in these areas has been impacted by the growth in VRE [60]. Regardless, at all of these specific hubs, negative pricing remains rare. In the real time market, negative pricing occurred 2% of hours or less in 2016; in the day ahead market—which is most relevant for inflexible baseload generation—negative pricing outside of California has been almost non-existent at these specific hubs.

[7] Further analysis of the time- and geographic- profile of negative pricing events can help identify some of the causes. For example, [4] find that the profile of negative pricing in ERCOT is correlated with wind production and [43] shows that negative prices occurred during daytime hours in 2016, times of high solar, whereas most were during night-time hours in 2012. [60] review numerous hubs in many of the U.S. ISOs/RTOs, tracking negative pricing trends over time and diurnally, finding that the trends in negative price hours is suggestive of a VRE impact.



Note: Real-time values are shown behind day-ahead values. The bars are not stacked on top of each other.

Sources: Negative price share comes from LBNL analysis of ABB Velocity Suite data. VRE regional penetration estimates come, in part, from annual wind generation reported in ABB's Velocity Suite divided by total generation in the region. Since ABB does not include generation <1 MW and since large-scale solar generation data were incomplete for the year 2016, we estimate solar generation based on state-level capacity, and regional capacity factors from NREL. Distributed solar generation is also added to total generation when calculating VRE penetrations.[8]

Figure 15. Frequency of Negative Wholesale Electricity Prices in the Real-Time and Day-Ahead Markets at Several Major Trading Hubs

We estimate the real-time wholesale price had there been no negative prices by comparing the actual average wholesale price to the average after replacing negative prices with $0/MWh. In effect, this removes any potential impact of policies like the PTC or RPS that would incentivize a VRE generator to submit a negative bid, though it also removes any impact of inflexible generation that sets the price with a negative bid. Given the rarity of negative pricing at most of these major trading hubs so far, it comes as little surprise that they have had almost no impact on average day-ahead prices and little impact on average real-time wholesale electricity prices at these specific hubs.

[8] Based on our calculation the VRE penetration in CAISO is 17.3% of in-region generation. Readers may be more familiar with penetration numbers based on served load. Accounting for distributed solar in both generation and load estimates, the CAISO VRE penetration is 16.1% of served load.

The only noticeable effect is CAISO, where real-time wholesale prices in 2015 were \$1.7/MWh (6%) lower due to negative prices than they would have been without negative prices. This gap equals \$0.9/MWh (3%) in 2016, and is expected to grow in the near term due to increases in VRE and high river flows driving increased production from hydropower facilities. At all other large trading hubs explored here, negative prices have had no noticeable effect on the *annual average* day-ahead or real-time wholesale prices for every year examined.

4.3. Contributors to Negative Pricing at Major Hubs

To understand which resources are potentially contributing to negative real-time prices at the selected major pricing hubs, we utilize hourly aggregate generation data provided by five ISOs (CAISO, ERCOT, SPP, MISO, and NYISO[9]). Specifically, we compare average generation—by generation type—during positive price hours to average generation during negative price hours in 2016 (Figure 16).[10] Note that some of the regions have a very low number of negative price hours, making generalizations difficult. Since the frequency of negative prices in CAISO was highest in 2011 we include an analysis of 2011 for CAISO in addition to 2016.

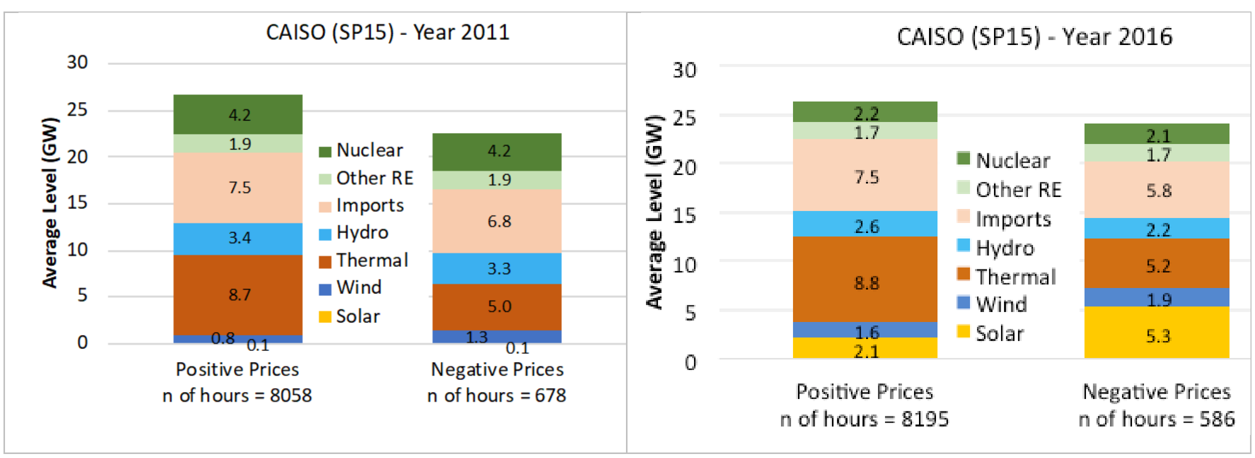
Except in MISO, negative prices in 2016 occurred at times when aggregate generation (and system load) was, on average, lower than load during positive price times. VRE also tended to generate more during negative price hours at major hubs than during positive price hours, though the contribution of VRE varies by technology and region. In 2016, solar in CAISO is clearly generating more during negative price hours at the SP15 hub, on average, than during positive price hours. But, in 2011, solar in CAISO was generating less on average during negative price hours at the SP15 hub. Solar was not generating at all during negative prices in 2016 in ERCOT or SPP. Wind is always generating more—on average—during negative price hours. In contrast,

[9] PJM only reports hourly wind generation, but not aggregate generation from other resources. ISO-NE does not report hourly aggregate generation of any resource. As such, neither PJM nor ISO-NE are included in this analysis.

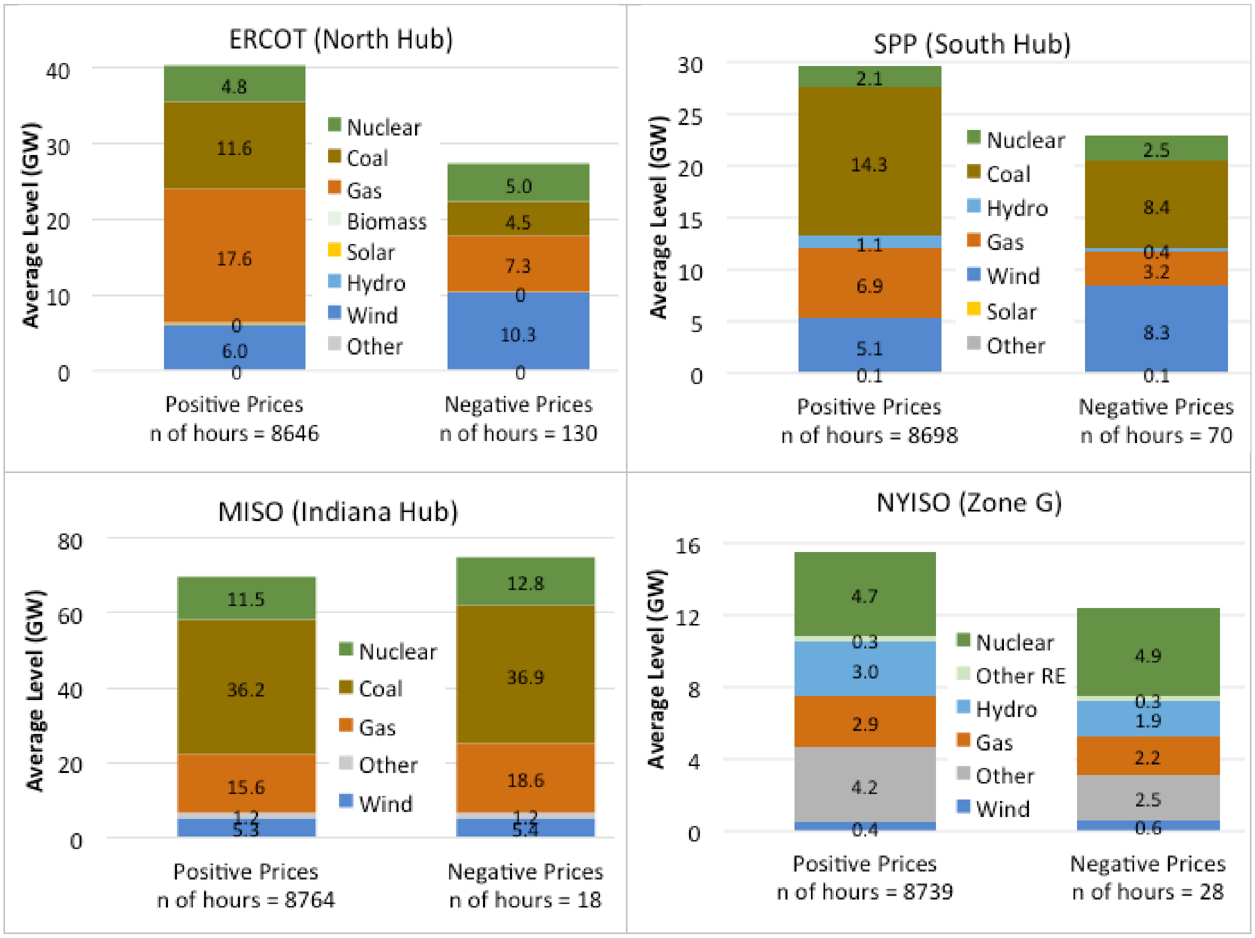
[10] In contrast to our approach, Goggin [61] explores the frequency of negative pricing hours that are specifically of the magnitude one might expect from the PTC and RPS. This method is appropriate if one is only interested in the 'bidding effect' of the PTC and RPS in inducing negative-priced bids. However, as described earlier, VRE can also influence the prevalence of negative prices in wholesale markets though the 'deployment effect' by virtue of affecting the supply stack with large volumes of zero-marginal-cost generation. Our approach implicitly accounts for both effects.

more flexible generation like hydro and gas tend to produce significantly less power on average during negative price hours than during positive price hours. Coal in ERCOT and SPP similarly produces less during negative price hours. Nuclear plants tend to operate at full power during periods of negative prices, and also during periods of positive prices.[11]

Even though negative prices had the highest frequency in 2011 at the SP15 hub in CAISO, comparison of the absolute level of generation in 2011 and 2016 shows that VRE was much lower in 2011. In 2011, hydropower and nuclear were considerably higher than in 2016 in both positive and negative price hours; imports also decreased to a lesser degree in 2011 during the negative price hours. As shown earlier in Figure 15, the frequency of negative prices dropped in 2012; this timing correlates with the 2 GW San Onofre Nuclear Generating Station being taken offline as well as a decline in hydropower output; the effect of hydropower on historical negative price events in California and the Northwest is also covered in [62]. This illustrates that the drivers for negative pricing are not limited to VREs but also arises during periods without much flexibility but with significant nuclear and hydropower generation. While VRE resources are generating more in negative price hours there are also many other generation resources generating at the same time.



[11] The lower average generation during positive price hours relative to negative price hours for nuclear plants in SPP and MISO was due to large nuclear outages that occurred during periods of positive prices. These outages led to lower nuclear production over the year, though the plants were closer to full output during negative price hours.



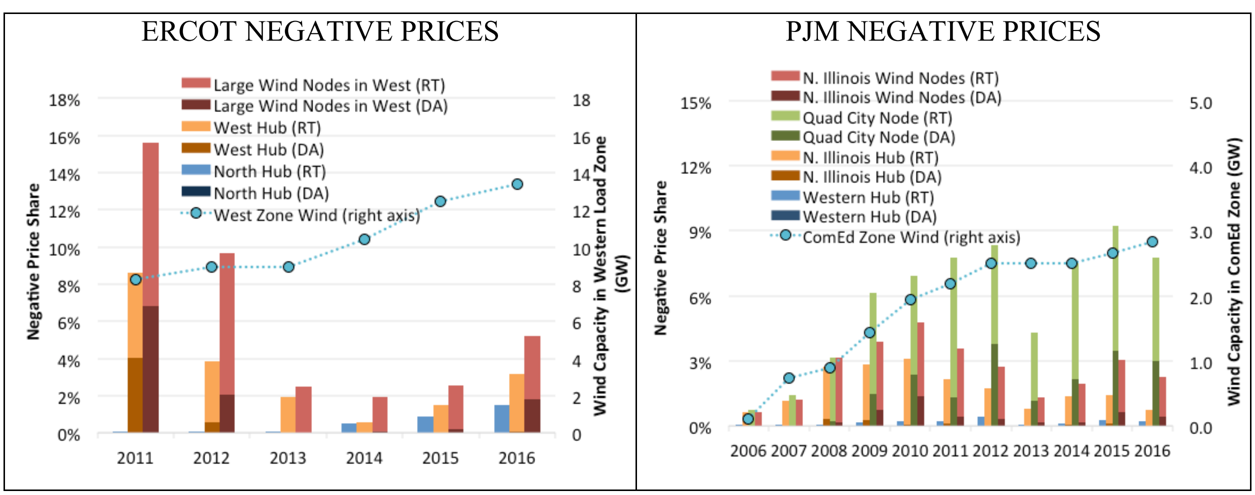
Source: LBNL analysis of ABB Velocity Suite data.

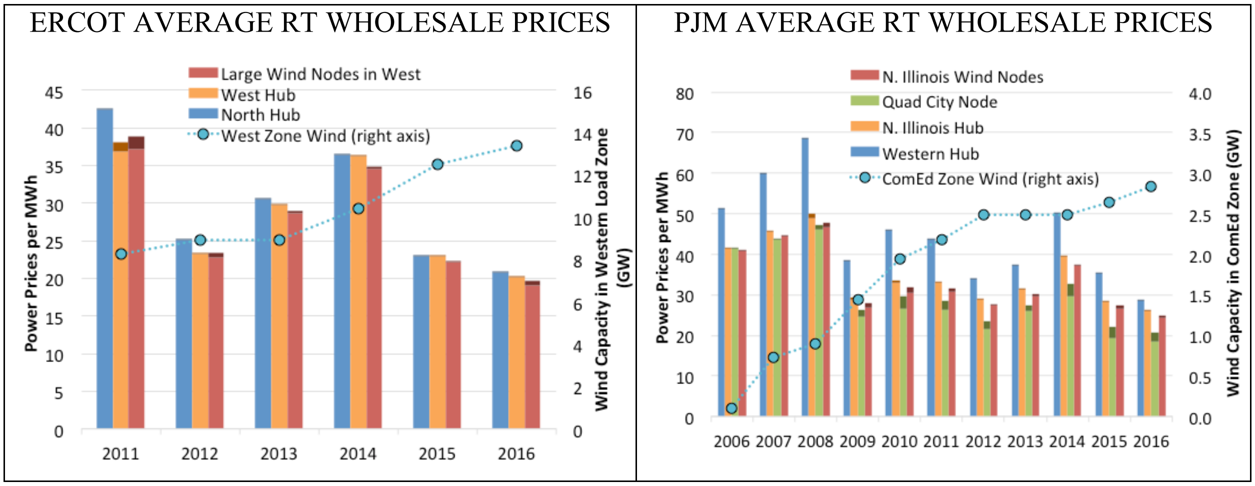
Figure 16. Generation of Various Resources during Positive and Negative Price Periods in 2016 (and, for CAISO, also 2011)

4.4. Locational Impacts: The Influence of Transmission Limits on Specific Trading Hubs

Major trading hubs do not reveal the full story of VRE impacts. Transmission limits between where generation is located and load centers can lead to congestion and a higher prevalence of negative pricing in constrained zones and nodes. According to a recent report by DOE, for example, PJM has indicated that impacts can be more severe on specific buses, and can impact the economics of specific generating units. In particular, PJM observed that "Since 2014, PJM has seen prices go negative at nuclear unit buses in approximately 2,176 hours—representing 14 percent of off-peak hours" [1]. West Texas, meanwhile, is a wind-rich region in ERCOT. Transmission investments through the CREZ initiative started to be completed in 2011, significantly reducing congestion in West Texas and the prevalence of negative price hours in that region.

To more systematically demonstrate the geographic differences in wholesale prices between major trading hubs and selected pricing nodes, Figure 17 compares the frequency of negative day-ahead and real-time prices and average annual real-time prices between the ERCOT North Hub, the ERCOT West Hub, and the average of ten pricing nodes in the West zone with the largest amount of wind power in 2016. Negative prices in real-time and day-ahead markets were significantly more prevalent in the wind-rich regions in 2011 and 2012 at the start of the CREZ transmission expansion, before declining dramatically through 2014 as the CREZ lines were completed [38]. Average annual real-time prices at the ERCOT West hub and the ten selected wind-rich pricing nodes have consistently been lower than prices at ERCOT North. Negative prices, in particular, caused the average *real-time* price at wind nodes to be nearly $2/MWh (5%) lower than they would have been without negative prices in 2011, though by 2016 the impact of negative prices was less than $0.6/MWh (3%). Negative prices caused the average *day-ahead* price at wind nodes to be $0.5/MWh (1%) lower than without negative prices in 2011, dropping $0.2/MWh (1%) less in 2016 (note, day-ahead prices are not shown in the figure). Negative prices—while still rare—are again on the rise since 2014 as wind penetration continues to increase in ERCOT; moreover, negative real-time prices are now spreading outside of the wind-rich West zone (see also, [4] and [60], which also evaluate ERCOT pricing).





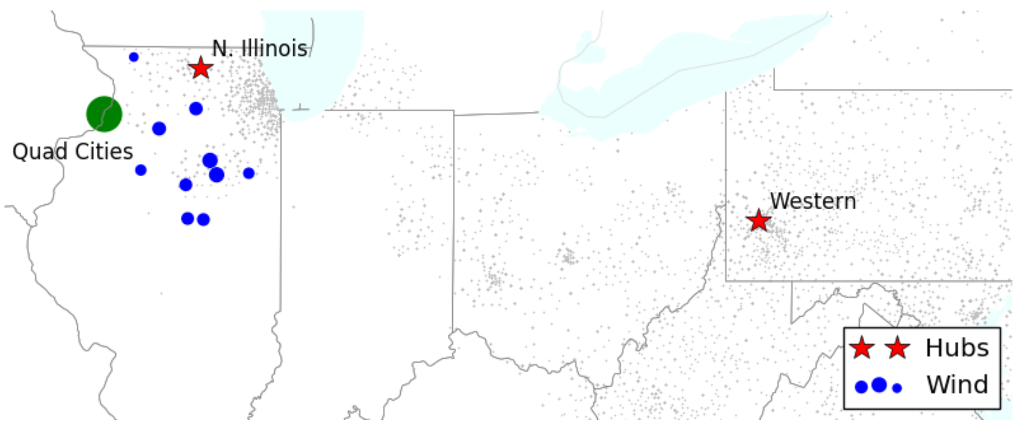
Note: Average real-time prices without negative prices are shown as the dark band stacked on top of the average wholesale prices with negative prices.

Source: LBNL analysis of ABB Velocity Suite data.

Figure 17. Comparison of Frequency of Negative Prices and Average Real-Time Prices between Major Trading Hubs and Constrained Nodes in ERCOT and PJM

The same comparison is conducted for the PJM Western Hub (in Pennsylvania) and the N. Illinois Hub, the latter of which is near a large nuclear plant (Quad City) and several wind plants in the ComEd zone of PJM (Figure 18); we therefore compile data on pricing at the two hubs, but also at the Quad City pricing node and various wind project pricing nodes (Figure 17 and Figure 18). Though negative pricing is infrequent at the PJM Western Hub, it is far more common at the other locations. This is particularly true at the Quad City node, where negative prices have occurred for more than 6% of the hours in seven out of the last eight years, and have reduced annual average *real-time* prices by roughly $2.3/MWh (10%) over the last eight years. Negative *day-ahead* prices have reduced the annual average day-ahead prices by less than $0.2/MWh (1%) over the same timeframe. The increase in the frequency of negative prices at the Quad City node tends to track the cumulative installed capacity of wind in the ComEd zone of PJM. On average, wholesale prices at the N. Illinois Hub, and at the Quad City and wind nodes analyzed here, are substantially lower than the PJM Western Hub. Persistent differences in LMPs across nodes may signal the need for additional investment in transmission to resource-rich areas. Additional factors to explore in future analysis include whether similar increases in negative prices are observed at other nuclear and other fuel plants in the ComEd region, additional factors other than growth in wind that may be correlated with the increase in frequency of negative pricing, and the extent to which the frequency of negative prices would be reduced without the PTC.

Related to these additional analysis possibilities, the PJM market monitor reports that 3-5% of the marginal units in the real-time market in PJM were wind between 2012 and 2016 while less than 0.1% of the marginal units were nuclear between 2012 and 2015 and 1% were nuclear in 2016 [63]. MISO, meanwhile, has areas where local prices are frequently set by wind, even though wind set the system-wide marginal price less than 1% of the time in 2016 [39]. Bajawa and Cavicchi [60], meanwhile, explore the frequency and temporal profile of negative pricing in a wide variety of hubs across the United States.



Source: Power plant capacity and plant zip code from ABB Velocity Suite data, with locations estimated from zip codes.

Figure 18. Location of Quad Cities Nuclear Plant, Large Wind Pricing Nodes, N. Illinois Hub, and Western Hub in PJM

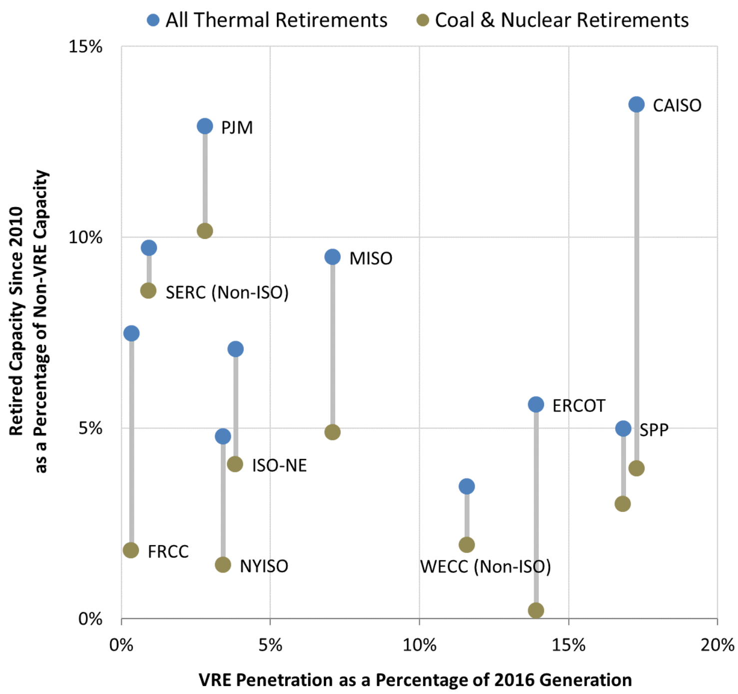
4.5. Impacts on Recent Thermal-Plant Asset Retirements

There has been a significant amount of retirements of thermal generation assets in recent years, with [1,64,65] and others finding that retiring coal and natural-gas plants tend to be older, smaller, less efficient, more-emitting, and operating at lower capacity factors than the remaining fleet. For example, as shown in [64], coal plants that retired between 2010-2016 had an average age of 52 years while coal plants that did not retire or are scheduled for retirement had an average age of 37 years in 2016. Retired coal plants had an average capacity of 122 MW, whereas plants not scheduled for retirement are larger at 239 MW on average. The heat rate of retired coal plants was slightly higher (10,386 Btu/kWh) than plants not scheduled for retirement (10,046 Btu/kWh), indicating that the plants that retired were also somewhat less efficient. The heat rate of retired gas plants (CCGT and CTs), meanwhile, was considerably larger than plants not scheduled for retirement. Finally, the most dramatic difference in the characteristics of retired coal plants compared to coal plants not scheduled to retire is the average SO_2 emissions rate: the average emissions rate of coal plants that retired between 2010-2016 was 1.2 lbs SO_2/MMBtu, while the emissions rate of the plants not scheduled for retirement was 0.2 lbs SO_2/MMBtu.

Plant retirements have been driven by a variety of market, policy, and plant-specific factors, with reductions in natural gas prices often identified as the most impactful single cause [1,52,54,65–68]. There is uncertainty, however, on the relative contributions of various factors, and on the specific role of VRE growth [1,7,68–74].

We explore whether VRE growth is correlated with regional retirement percentages (2010-2016 retirements, relative to total non-VRE capacity in 2016) in Figure 19. Visual inspection does not offer perfect clarity, thought there does not appear to be any obvious widespread relationship between VRE penetration and recent historical regional retirement decisions. PJM and SERC, both with very low VRE penetrations, have among the largest amount of recent total thermal-plant and coal & nuclear plant retirement. ERCOT, SPP, and the non-ISO portion of the Western Electricity Coordinating Council (WECC) region, on the other hand, all have sizable VRE penetrations but low retirement percentages. CAISO has experienced strong growth in VRE and has the highest level of total thermal-plant retirements on a percentage basis, most of which are older natural-gas steam plants; many of those plants have retired as a compliance mechanism with California's policy to phase out once-through cooling [75].

In contrast, we see stronger relationships between regional retirement differences and factors including SO_2 emissions rates (for coal), planning reserve margins (for all thermal units), variations in load growth or contraction (for all thermal units), and the age of older thermal plans (for all thermal units).[12]



Source: Historical retirement data from ABB's Velocity Suite dataset [44], accessed in May 2017. VRE regional penetration estimates come, in part, from annual wind generation reported in ABB's Velocity Suite divided by total generation in the region. Since ABB does not include generation <1 MW and since large-scale solar generation data were incomplete for the year 2016, we estimate solar generation based on state-level capacity, and regional capacity factors from NREL. Distributed solar generation is also added to total generation when calculating VRE penetrations.

Figure 19. Correlation Chart of VRE Penetration and Regional Retirement Trends

Visual inspection of correlation charts is not dispositive in establishing causal relationships, but it does support the statement that VRE growth has, so far, had relatively little obvious *widespread* impact on retirements. This is consistent with the findings presented earlier on the relatively modest impact of VRE on average wholesale power prices, at least at the selected major trading hubs.

[12] Additional correlation charts are presented in [64]

Notwithstanding the limited evidence of a widespread impact of VRE on historical retirement decisions, that is not to say that VRE has had no such impact, or will not in the future. Growth in VRE does place some downward pressure on wholesale prices and tends to reduce the capacity factors of thermal plants; these effects tend to be larger in transmission-constrained zones and when there are lower levels of overall flexibility. Inflexible generation sources may be at special risk given these dynamics. In part as a result, Pacific Gas and Electric (PG&E) specifically notes growing levels of VRE as one of the many reasons to retire the Diablo Canyon nuclear plant in California [76].

5. Discussion and Conclusions

The surveyed studies are generally in agreement that increasing VRE penetrations will decrease average wholesale energy prices (i.e., LMPs) in the short run (in non-restructured electricity markets, meanwhile, VRE would be expected to reduce average short-run marginal operating costs). The long-run wholesale energy price impacts are less clear as many of the surveyed studies do not reflect long-run equilibrium conditions. In the long run (and at fixed VRE levels), price impacts may be less pronounced due to changes in the generation mix as that mix adapts to higher levels of VRE.

Our analysis of electricity market data through 2016 indicates that VRE so far has had a relatively modest impact on historical average annual wholesale prices across entire market regions, at least in comparison to other drivers; this is true even in those ISOs with the largest VRE penetrations. The reduction of natural gas prices is the primary contributor to the decline in wholesale prices since 2008. And, because of the low price of natural gas, regional ‘supply curves’ are particularly flat; this is a core reason why VRE has had a relatively modest impact on annual prices so far. Some of the surveyed studies similarly demonstrated that changes in natural gas prices have a significant impact on wholesale electricity prices. In many cases, natural gas price sensitivity scenarios produced price impacts that were comparable to impacts produced by the VRE scenarios.

Very few of the surveyed studies present results on price variability. Those that did indicated that electricity price variability may increase with increasing VRE penetrations, particularly with high solar generation. Our analysis of historical market data provides some evidence that that the temporal and geographic patterns in wholesale prices have changed in areas with higher levels of VRE. Specifically, negative prices have sometimes increased with VRE, though the prevalence of negative pricing so far remains limited at most of the selected large pricing hubs that are the focus of our analysis, and the net impact of negative prices on overall average wholesale prices at these same hubs has also been minor. CAISO pricing is, to a degree, the exception. Moreover, negative pricing is a larger issue in specific, often transmission-constrained zones, and especially during periods of relatively low system-wide load. We find that VRE is generally correlated with negative price hours; inflexibly operated nuclear plants are also major contributors. Wide variation in prices and periods of negative prices may increase the attractiveness of increasing in energy storage which, in turn, would mitigate the price effects. Recent decreases in the cost of storage suggest the role of storage should be considered in more detail than it has been in the studies reviewed here.

Though wholesale energy prices (LMPs) are anticipated to decline with increasing VRE, the surveyed studies show a general trend of increasing prices for regulation reserves with increasing VRE penetrations. Prices for spinning and non-spinning reserves (reserve levels for which are often set by the single largest contingency, and not VRE) appear to be more stable, however the picture is less clear for these reserve products given limited coverage in the literature.

The reviewed forward-looking studies generally did not model retirement decisions of specific plants, in fact, most assumed fixed generation portfolios and did not consider unit retirements driven by economics at all. However, several studies did attempt to project changes in revenues and profits that would be experienced in a high VRE future. These studies generally found nuclear and coal operating profits and revenues were to decrease with increasing VRE penetrations, however the magnitude of this effect differed between studies. The operating profits (i.e. revenue minus operating costs) of natural gas fired generators are less exposed to increasing VRE levels given their flexibility characteristics and resultant ability to dispatch down and reduce operating costs when wholesale prices are low. Studies differed in how they account for different potential revenue streams, e.g. few studies comprehensively included possible revenues from capacity and ancillary service markets, making comparisons difficult. The surveyed results unfortunately do not provide insight into whether or not, or the extent to which, these revenues changes may motivate unit retirements in the future. Our analysis of historical data shows that although some specific power plants may have retired in part due to the impacts of VRE, we find little relationship between the location of recent thermal-plant retirements and VRE. Moreover, given the relatively modest impact of VRE on average annual wholesale electricity prices across large market regions, it is unlikely that VRE has influenced retirements on a *widespread* basis so far.

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Table 4. Studies Reviewed to Assess Potential Impacts of VRE on the Bulk Power System

Title	Author	Year Published	Region	Target Year	Model	Key Scenarios
Thermal Capacity Fixed Across VRE Penetrations						
Western Wind and Solar Integration Study: Phase 1 [24]	GE Energy	2010	WestConnect	2017	MAPS	· 3% wind, 0% solar · 10% wind, 1% solar · 20% wind, 3% solar · 30% wind, 5% solar
Growing Wind: Final Report of the NYISO 2010 Wind Generation Study [25]	NYISO	2010	NYISO	2018	GridView	· 1,275 MW wind (current) · 8,000 MW wind total (10%+)
Western Wind and Solar Integration Study: Phase 2 [20]	Lew et al.	2013	Western Interconnection	2020	ReEDS/PLEXOS	· No renewables · 9.4% wind, 3.6% solar · 25% wind, 8% solar · 4. 8% wind, 25% solar · 16.5% wind, 16.5% solar
Fundamental Drivers of the Cost and Price of Operating Reserves [23]	Hummon et al.	2013	Colorado	2020	PLEXOS	· 15% - 35% VRE
PJM Renewable Integration Study [26]	GE Energy	2014	PJM	2026	GE MAPS	· 2% VRE · 14% VRE · 20% VRE (several cases) · 30% VRE (several cases)
Market Effects of Wind Integration in ERCOT [27]	LCG Consulting	2016	ERCOT	2021	UPLAN	· 15.8 GW wind · 22.9 GW wind · 30 GW wind
The Impact of Wind Power on Electricity Prices [77]	Brancucci Martinez-Anido et al.	2016	ISO-NE	Not specified	PLEXOS	· 0% wind · 5.0% wind · 8.6% wind · 15.6% wind · 21.2% wind

Impact of Market Behavior, Fleet Composition, and Ancillary Services on Revenue Sufficiency [28]	Frew et al.	2016	ERCOT	2012 to 2014	PLEXOS	· 10% wind · 20% wind · 20% wind w/ flexibility req.
Solar PV Integration Cost Variation Due to Array Orientation and Geographic Location in the Electric Reliability Council of Texas [33]	Deetjen et al.	2016	ERCOT	2012	PLEXOS	· 9.3% wind · 9.3% wind + 6.8% solar
Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California [78]	Brinkman et al.	2016	California	2030	PLEXOS	· 20% solar + 7% wind · 24% solar + 18% wind
Thermal Capacity Varied With VRE Penetration						
Eastern Wind Integration and Transmission Study [21]	EnerNex Corporation	2011	Eastern Interconnection (EI)	2024	PROMOD	· 6% wind · 20% wind (3 cases) · 30% wind
Renewable Energy Futures Study [19]	Hand et al.	2012	United States	2050	ReEDS and GridView	·6.9% VRE (baseline) ·13.7% - 64.1% VRE
The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region [79]	Fagan et al.	2012	MISO	2020 and 2030	ProSym	· 10 GW wind · 30-50 GW wind (2020) · 60-110 GW wind (2030)
Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California [31]	Mills and Wiser	2012	CAISO	2030	Original model	· 0% - 40% wind · 0% - 40% solar
Exploring Natural Gas and Renewables in ERCOT Part II: Future Generation Scenarios for Texas [34]	Shavel et al.	2013	ERCOT	2032	Xpand/PSO	· Reference · High Gas, Low Renewable Costs (HGLR) · HGLR + Stringent Carbon Rule
Electricity market design for generator revenue sufficiency with increased variable generation [29]	Levin and Botterud	2015	ERCOT	2024	Original model	· 10% - 40% wind

Eastern Renewable Generation Integration Study [22]	Bloom at al.	2016	Eastern Interconnection (EI)	2026	ReEDS/PLEXOS	· 3% wind, 0% solar · 12% wind, .25% solar · 20% wind, 10% solar · 25% wind, 5% solar
NESCOE Issues Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study [30]	NESCOE	2017	ISO-NE	2025 and 2030	Original model	· 26.28%/28.71% RPS (2025/2030) · 35%/40% RPS (2025/2030) · 40%/45% RPS (2025/2030)
Economic and technical challenges of flexible operations under large-scale variable renewable deployment [32]	Bistline	2017	CAISO and ERCOT	2030	US-REGEN	· 0-100 GW wind (ERCOT) · 0-100 GW solar (CAISO)